Kangley Echo Lake
Economic Screening and Sensitivity Analysis Report

Energy and Environmental Economics, Inc. (E3)
San Francisco, CA

Awad & Singer
Oakland, CA

Nexant, Inc.
San Francisco, CA

Tom Foley
Consultant
Portland, OR

November 8, 2002

Prepared for:
The Energy Efficiency Group & Transmission Business Line
Bonneville Power Administration
Portland, Oregon

Section 1. Executive Summary

Bonneville Power Administration (BPA) proposed the Kangley-Echo Lake transmission line to meet system reliability threats brought about by load growth in the Puget Sound region and treaty obligations to return energy to Canada. These conditions create the possibility of a blackout in the Puget Sound area if certain contingencies, such as a transmission line outage, were to occur during extreme cold weather.

The proposed 500kV line would connect the existing Schultz-Raver 500 kV line with BPA's Echo Lake substation in the Maple Valley area. The proposed route may cross the Cedar River watershed, which provides drinking water for the City of Seattle. BPA funded this study to explore the feasibility of pursuing alternatives to building the Kangley-Echo Lake (KEL) line.

The study team consisted of experts from Energy and Environmental Economics (E3), Awad & Singer, Nexant, Inc., and Tom Foley Consultants. The goals of this evaluation were to:

1. Identify technologies that would be cost effective alternatives to KEL.
2. Evaluate the sensitivity of the cost effectiveness analysis to variations in key input assumptions.
3. Estimate whether achievable load reduction from those cost effective alternatives would be sufficient to defer the line.

1.1 Summary of Approach

We analyzed the cost effectiveness of a broad range of alternatives including Demand-Side Management (DSM), Distributed Generation (DG), large scale Generation (G), and Demand Response and Direct Load Control (DR-DLC). Our analysis estimated the costs and benefits of each alternative from six stakeholder perspectives:

1. BPA TBL Ratepayers (RIM)
2. BPA TBL Revenue Requirement (Utility Cost Test)
3. Total Resource Cost
4. Societal Cost
5. Participants
6. Local Distribution Company (LDC) Ratepayers (RIM)

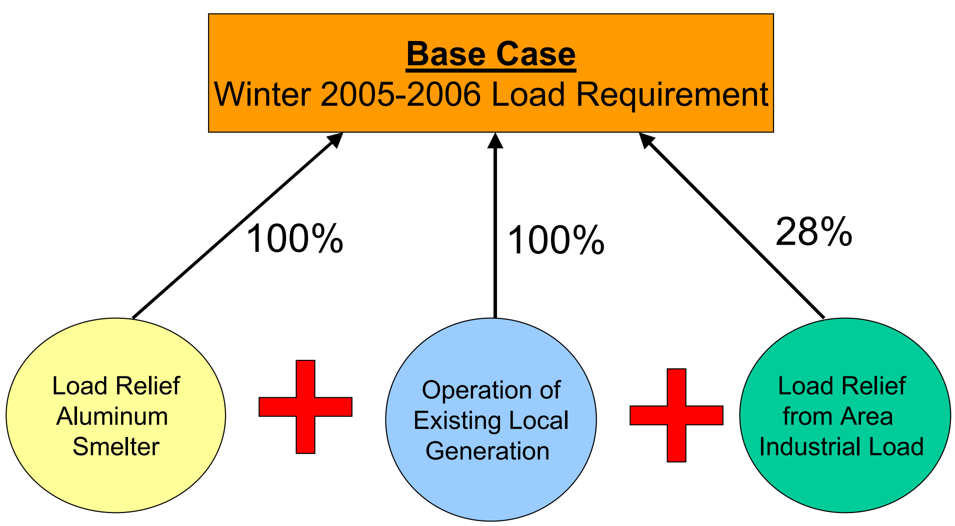
Our analyses of the economics and the required penetration of alternatives were based on BPA system planning information on the transmission system, the proposed KEL line and the conditions requiring additional capacity. In addition, BPA provided general economic assumptions and system characteristics. The team developed the list of alternatives and their cost and performance characteristics from third party sources including the Northwest Power Planning Council DSM database.

1.2 Summary of Findings

A high level of load reduction or additional generation is required to defer KEL. Based on the planning assumptions provided, the level of load reduction required to prevent an overload on the transmission system and to maintain system reliability during a major system outage is approximately 122 megawatts (MW) at the Covington transmission substation during the winter of 2003-2004. This load reduction requirement amount increases every year thereafter. The analysis of the load requirement in Section 4 provides a thorough description of the load forecasting process.

The Puget Sound Area peak load is approximately 12,000MW. Because of the way that power flows over the network of transmission facilities, each MW of load reduction or additional in-area generation only reduces the flows across the Covington transformer by a fraction of a MW. For example, a 100MW load reduction in downtown Seattle will only reduce loadings on the Covington transformers by 42MW, while the same reduction in Tacoma would only achieve a 20MW reduction at Covington. The ratio of the MW change at Covington to the MW change at the source is called the load flow distribution factor (or distribution factor). When applying these factors, the 122MW that are required to bring the peak load of Covington below overload levels in the first year translates to approximately 381MW of load reduction or additional generation within the Puget Sound Area assuming a distribution factor of 32%[1]. Thereafter, the amount of load reduction or additional generation needed to prevent an overload increases annually. By the winter of 2005-2006 the needed amount grows to 269MW at Covington, or 841MW within the Puget Sound Area. As illustrated in Figure 1, a 3-year deferral of the line would require 100% of the available load relief from the large aluminum smelter in the area, plus operation of all existing generation not expected to be on-line, plus load relief from 28% of industrial load in the area. To put the 28% industrial participation rate in perspective, we reviewed information from 13 utility DR programs, and found only four with participation rates above 5%.

Figure 1: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Base Case Assumptions)



[1] 32% is the load weighted average distribution factor across the Puget Sound study area.

Transmission avoided costs are low. The avoided cost of the KEL project, assuming a cost of $25 million and annual operations and maintenance (O&M) costs of $50,000 for the line, is approximately $1.49 million per year (as calculated using the differential revenue requirement method described in Section 3.2 of this report). Therefore, in order to prevent increasing TBL's revenue requirement, 122MW of demand reduction at Covington would have to be purchased for $1.49 million or less. This equates to approximately $12.25 per kW at Covington per year or $3.92 per kW-year in the Puget Sound Area based on average load flow distribution factors.

Furthermore, TBL estimates that construction of the KEL line would reduce peak losses on the transmission system by 11MW. This would result in annual energy savings of 48,180MWh, valued at nearly $2 million dollars.[2] Therefore, the economic value of the energy savings is greater than the benefit of deferring the line.

Incentive Levels are low compared to other programs. The likelihood of achieving significant penetration in the area with incentive levels calculated from the avoided cost of deferring the KEL line cannot be determined precisely without a detailed customer assessment. To provide BPA with some general indication, however, we compared incentive levels and penetration rates for 19 demand response programs across the United States with the incentive levels and penetration rates required for cost-effective deferral of the KEL line. From this comparison we conclude that it is unlikely the available incentive payments based on the value of deferring the KEL line would be sufficient to achieve the significant penetration required in this case. Any DR-DLC program designed to meet the load relief needs at Covington would need to achieve higher penetration with a lower incentive level than the programs we observed in our survey.

Demand response is the most cost-effective alternative from a TBL rate perspective. Of the alternatives considered, we found that demand response programs are most likely to be cost-effective from the utility rate perspective and to participants. Demand response is well suited to solving the capacity problem without causing significant revenue loss since it focuses load reduction on only the hours when needed for system reliability. We found, however, that demand response is not cost effective from the TRC perspective because deferral of the line would eliminate the significant loss savings BPA expects the line to achieve. DSM is cost-effective from a TRC perspective, but is not likely to produce win-win outcomes because there would be increased pressure on rates due to increased efficiency, and subsequently reduced utility sales throughout the year or season. We found that DSM programs would need to reduce energy each year from half to one and a half times the annual energy growth. Also, DSM efforts would either have to be funded externally to BPA or the additional costs would have to be passed through to TBL's ratepayers, because the DSM measures do not pass TBL's RIM test.

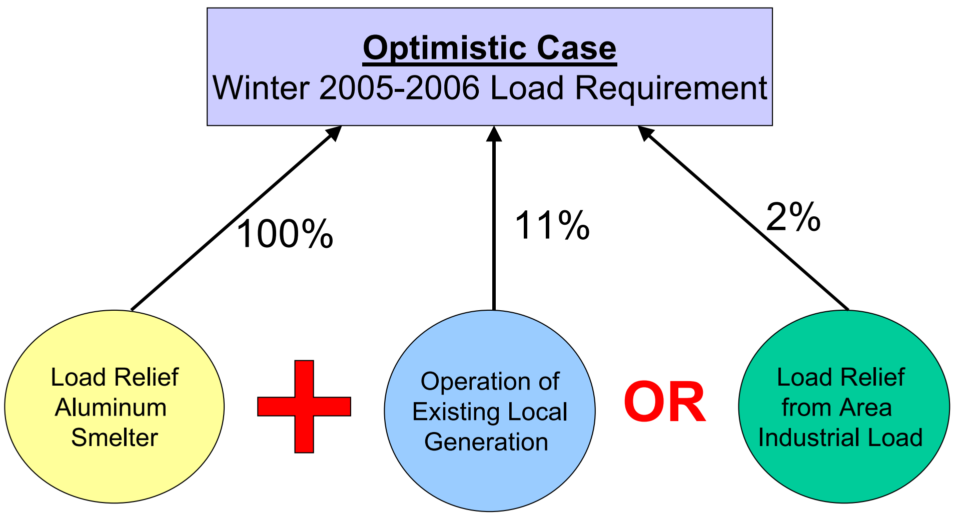
Scenario analysis indicates alternatives could be cost effective if demand is lower than forecast. To provide BPA with a comprehensive assessment of the potential for cost effective alternatives to the KEL line, we conducted a scenario analysis. The purpose of the analysis was to evaluate the sensitivity of cost effectiveness results to changes in key economic inputs. We tested the entire range of alternative technologies under three sets of economic assumptions. These included the base case which we largely derived from BPA's transmission planning work, an 'optimistic' case that improves the cost-effectiveness and penetration requirements of alternatives, and a 'pessimistic' case that reduces the cost-effectiveness of alternatives. The base case represents our best estimate of the future, and the 'optimistic' and 'pessimistic' cases represent extremes that have a low probability of occurring. We found the KEL line was the most

[2] Assumes the 'base case' market price of $40.03 /MWh.

cost-effective solution to capacity constraints in both the base and pessimistic cases. In the optimistic case, we found DR and generation were cost effective from both the ratepayer and participant perspectives.

In this optimistic case we estimated that BPA would require 82MW of load reduction at the Covington substation to defer the line for 3 years or 256MW within the Puget Sound Area. As illustrated in Figure 2, this can be achieved through 100% of available load relief from the large aluminum smelter in the area, plus either operation of 11% of existing generation not expected to be on-line or load relief from 2% of industrial load in the area.

Figure 2: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Optimistic Assumptions)



1.3 Summary

The decision whether to build the line or defer the line depends on expectations of demand and the availability of funds for alternatives. Three scenarios were examined to provide insight into this decision. If demand increases at the forecasted rates and funds for alternatives are limited to the value of deferring the line, then the KEL line is the most cost effective and feasible solution. However, if demand were to be significantly lower than expected, then sufficient load reduction potential of alternatives exists to mitigate the need for the line. In this case, the economics of alternatives would also be improved, and it might be possible to defer the line for up to 3 years with demand response programs and contracts with existing generation in the area. Likewise, if additional benefits of alternatives were to be found to offset the costs (for example, through partnering with local distribution utilities), the cost-effectiveness of alternatives could be improved. On the other hand, if demand were to increase at a higher rate than forecasted, then the KEL would again be the most cost-effective and feasible solution.

There are competing views of the appropriate criterion for cost effectiveness. The principal debate is between the Ratepayer Impact Measure (RIM) and the Total Resource Cost test (TRC). RIM compares the effect on TBL's rates of the cost of alternatives versus the capital and maintenance costs of a proposed solution. TRC compares the costs and benefits of alternatives with all the costs and benefits of a proposed solution. TRC includes energy and generation benefits. An alternative deemed cost effective under TRC could cause rates to be higher. While our analysis provides information to evaluate these two criteria, it was not intended to provide guidance as to the appropriateness of one over the other.

Independent of BPA's decision regarding the KEL line, the distribution system benefit of alternatives is an avenue of additional investigation that was not within the scope of this project, but should be pursued. If distribution benefits are significant, they would increase the value of alternative measures and should provide additional sources of funding. The incorporation of distribution benefits involves institutional and policy considerations that are beyond the scope of this analysis and will require more time for resolution than is available for the KEL line decision process.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

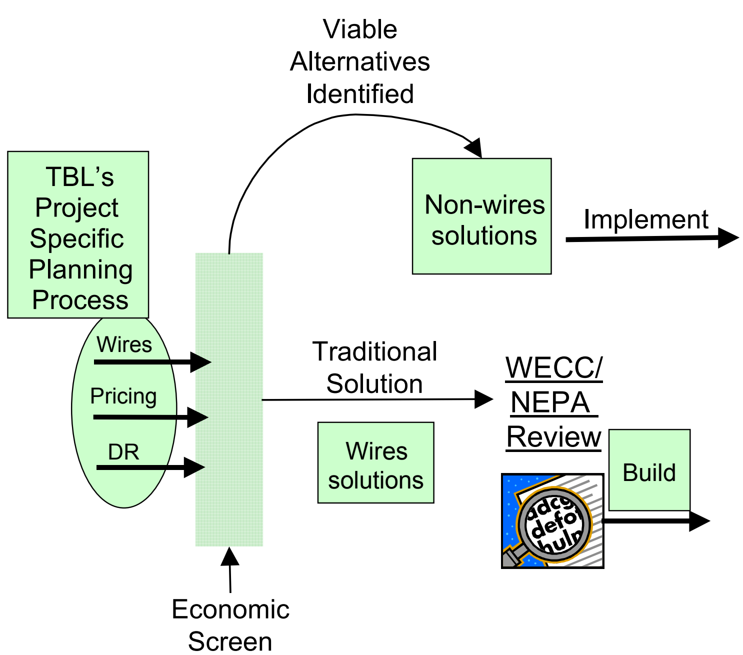
Section 2. Introduction

2.1 Background

Prior to proceeding with the construction of transmission projects, Bonneville Power Administration's (BPA) Transmission Business Line (TBL) is obligated to ensure that there is a clear and compelling demonstration of project need, and that the proposed project provides the most cost-effective solution to the region's transmission problems from an engineering, economic, and environmental standpoint. As part of its evaluation, BPA must consider whether non-transmission options can be employed as viable alternatives to transmission expansion. Non-transmission solutions include, but are not limited to: pricing strategies, demand reducing strategies, and strategic placement of generators. BPA retained the team of Energy and Environmental Economics, Inc. (E3), Awad & Singer, Nexant, Inc., and Tom Foley to conduct an economic screening of non-transmission alternatives to their proposed construction of the Kangley – Echo Lake (KEL) transmission line.

BPA commissioned this study with the intent of setting a precedent for the evaluation of alternatives for future transmission projects in keeping with the 'Expansion of BPA Transmission Planning Capabilities' document issued in November 2001. The goal is to make the planning process more proactive and expansive in identifying and resolving transmission problems at the lowest cost to the transmission system. It is TBL's intent that transmission projects, for which viable alternatives might exist, will be screened against the costs of strategically located and operated generation, demand management, and transmission-pricing programs (see Figure 3).

Figure 3: Economic Screening of Non-Wires Alternatives



2.2 The Kangley-Echo Lake Transmission Project

The need for the KEL Transmission Project is based on BPA TBL's projected overloads for winter 2003-2004. This projected overload is the product of a variety of factors that result in higher flows of energy northbound into the Puget Sound area. Factors contributing to the overload include: the projected growth of peak loads in the Puget Sound area, increased power return obligations to Canada under the Columbia River Treaty (the Canadian Entitlement Return), and the anticipated effect of extremely cold weather on Puget Sound area peak loads. One factor that can actually *reduce* transmission demand is the amount of local generation that is operating during peak periods. These factors are used as inputs to a BPA TBL load flow analysis that projects the loading on critical elements in the Puget Sound area under various system contingencies such as generator or transmission line outages. If the projected loading under specified contingencies exceeds equipment ratings on any critical elements, BPA TBL must take action to avoid being in violation of Western Electricity Coordinating Council (WECC) reliability criteria.

BPA studies show that, under certain contingencies, overloads can occur on a variety of elements in the Puget Sound area, including two 500 kV transformer banks at BPA's Covington substation near Enumclaw. At the direction of BPA, our study focused on the loading at the Covington transformer banks. Alternatives that reduce loading on these transformer banks to below their emergency limit will also prevent overloads on the other elements of the transmission system. The Covington transformers have a combined rating of 2,850 MVA. BPA conducted load flow studies for heavy load conditions in winter 2003-2004, and concluded that certain contingencies would cause an overload of 122 MW on the Covington transformer banks. We used BPA's load projections in conjunction with load duration curves from historical years in which extreme cold weather events occurred to develop MW and duration targets for transmission alternatives. The projected overloads, and number of hours during which overloads occur, are presented below in Table 1.

Any alternatives to construction of the KEL transmission line must maintain WECC reliability criteria. Therefore, measures that mitigate the overloads on the Covington transformers must be in place before the winter of 2003/2004 for the KEL line to be deferred or replaced.

Table 1: Projected Covington Transformer Bank Overloads, 2004-2013

Year	Maximum Overload (MW)	Number of Hours Overload Occurs
2004	122	10
2005	190	17
2006	269	30
2007	397	51
2008	449	61
2009	505	70
2010	558	86
2011	611	102
2012	664	119
2013	714	135

2.3 Project Goals

The team conducted an economic screen of non-transmission alternatives to the construction of the KEL transmission line that entailed: 1) Identifying any technologies or measures that would be cost-effective non-wires alternatives to the construction of the transmission line; 2) Estimating whether the achievable load reduction from those cost effective alternatives would be sufficient to defer construction of the line; and 3) Identifying and describing the scenarios and input assumptions under which there would be potential for line deferral.

In order to be successful, the combined load impact of the alternatives would have to satisfy the BPA TBL mandate to maintain transmission reliability based on WECC standards. If the combined impact falls short of the peak load requirements, then the line will have to be constructed to maintain reliability and there will be no capacity value to the alternatives in delaying the line. The load requirement to maintain reliability is based on the same forecasts that BPA TBL transmission planners have used to develop the proposed design of the new KEL line. In addition, we have explored alternative levels of load reduction using scenario analysis in order to develop more robust conclusions on the potential for KEL deferral.

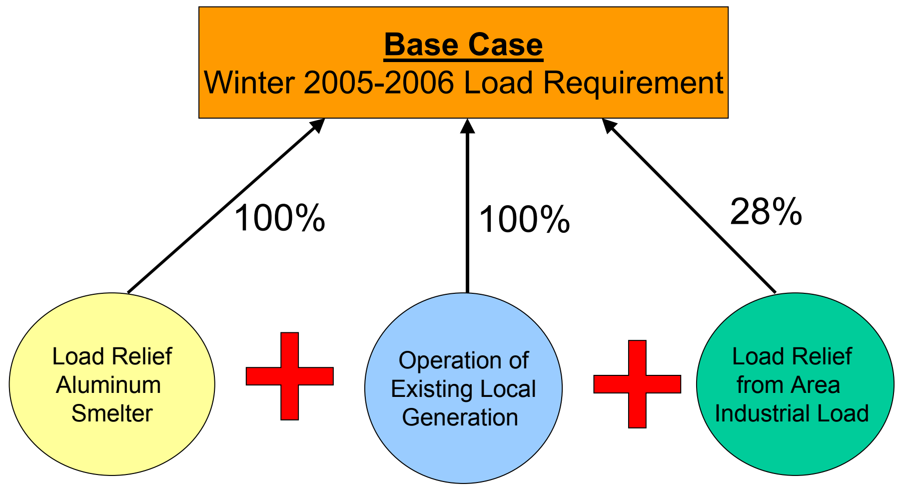
2.4 Summary of Results

A high level of load reduction or additional generation is required to defer KEL. Based on the planning assumptions provided, the level of load reduction required to prevent an overload on the transmission system and to maintain system reliability during a major system outage is approximately 122 megawatts (MW) at the Covington transmission substation during the winter of 2003-2004. This load reduction requirement amount increases every year thereafter. The analysis of the load requirement in Section 4 provides a thorough description of the load forecasting process.

The Puget Sound Area peak load is approximately 12,000MW. Because of the way that power flows over the network of transmission facilities, each MW of load reduction or additional in-area generation only reduces the flows across the Covington transformer by a fraction of a MW. For example, a 100MW load reduction in downtown Seattle will only reduce loadings on the Covington transformers by 42MW, while the same reduction in Tacoma would only achieve a 20MW reduction at Covington. The ratio of the MW change at Covington to the MW change at the source is called the load flow distribution factor (or distribution factor). When applying these factors, the 122MW that are required to bring the peak load of Covington below overload levels in the first year translates to approximately 381MW of load reduction or additional generation within the Puget Sound Area assuming a distribution factor of 32%[3]. Thereafter, the amount of load reduction or additional generation needed to prevent an overload increases annually. By the winter of 2005-2006 the needed amount grows to 269MW at Covington, or 841MW within the Puget Sound Area. As illustrated in Figure 4, a 3-year deferral of the line would require 100% of the available load relief from the large aluminum smelter in the area, plus operation of all existing generation not expected to be on-line, plus load relief from 28% of industrial load in the area. To put the 28% industrial participation rate in perspective, we reviewed information from 13 utility DR programs, and found only four with participation rates above 5%.

[3] 32% is the load weighted average distribution factor across the Puget Sound study area.

Figure 4: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Base Case Assumptions)



Transmission avoided costs are low. The avoided cost of the KEL project, assuming a cost of $25 million and annual operations and maintenance (O&M) costs of $50,000 for the line, is approximately $1.49 million per year (as calculated using the differential revenue requirement method described in Section 3.2 of this report). Therefore, in order to prevent increasing TBL's revenue requirement, 122MW of demand reduction at Covington would have to be purchased for $1.49 million or less. This equates to approximately $12.25 per kW at Covington per year or $3.92 per kW-year in the Puget Sound Area based on average load flow distribution factors.

Furthermore, TBL estimates that construction of the KEL line would reduce peak losses on the transmission system by 11MW. This would result in annual energy savings of 48,180MWh, valued at nearly $2 million dollars.[4] Therefore, the economic value of the energy savings is greater than the benefit of deferring the line.

Incentive Levels are low compared to other programs. The likelihood of achieving significant penetration in the area with incentive levels calculated from the avoided cost of deferring the KEL line cannot be determined precisely without a detailed customer assessment. To provide BPA with some general indication, however, we compared incentive levels and penetration rates for 19 demand response programs across the United States with the incentive levels and penetration rates required for cost-effective deferral of the KEL line. From this comparison we conclude that it is unlikely the available incentive payments based on the value of deferring the KEL line would be sufficient to achieve the significant penetration required in this case. Any DR-DLC program designed to meet the load relief needs at Covington would need to achieve higher penetration with a lower incentive level than the programs we observed in our survey.

Demand response is the most cost-effective alternative from a TBL rate perspective. Of the alternatives considered, we found that demand response programs are most likely to be cost-effective from the utility rate perspective and to participants. Demand response is well suited to solving the capacity problem without causing significant revenue loss since it focuses load

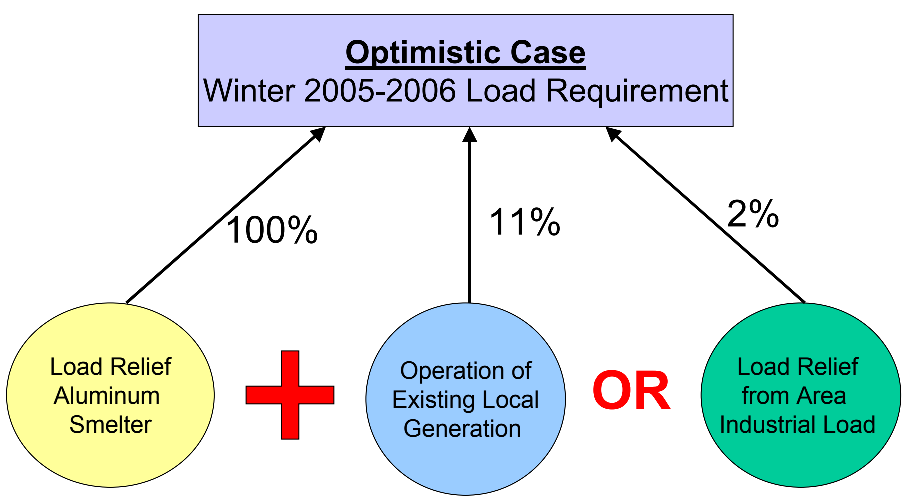
[4] Assumes the 'base case' market price of $40.03 /MWh.

reduction on only the hours when needed for system reliability. We found, however, that demand response is not cost effective from the TRC perspective because deferral of the line would eliminate the significant loss savings BPA expects the line to achieve. DSM is cost-effective from a TRC perspective, but is not likely to produce win-win outcomes because there would be increased pressure on rates due to increased efficiency, and subsequently reduced utility sales throughout the year or season. We found that DSM programs would need to reduce energy each year from half to one and a half times the annual energy growth. Also, DSM efforts would either have to be funded externally to BPA or the additional costs would have to be passed through to TBL's ratepayers, because the DSM measures do not pass TBL's RIM test.

Scenario analysis indicates alternatives could be cost effective if demand is lower than forecast. To provide BPA with a comprehensive assessment of the potential for cost effective alternatives to the KEL line, we conducted a scenario analysis. The purpose of the analysis was to evaluate the sensitivity of cost effectiveness results to changes in key economic inputs. We tested the entire range of alternative technologies under three sets of economic assumptions. These included the base case which we largely derived from BPA's transmission planning work, an 'optimistic' case that improves the cost-effectiveness and penetration requirements of alternatives, and a 'pessimistic' case that reduces the cost-effectiveness of alternatives. The base case represents our best estimate of the future, and the 'optimistic' and 'pessimistic' cases represent extremes that have a low probability of occurring. We found the KEL line was the most cost effective solution to capacity constraints in both the base and pessimistic cases. In the optimistic case, we found DR and generation were cost effective from both the ratepayer and participant perspectives.

In this optimistic case we estimated that BPA would require 82MW of load reduction at the Covington substation to defer the line for 3 years or 256MW within the Puget Sound Area. As illustrated in Figure 5, this can be achieved through 100% of available load relief from the large aluminum smelter in the area, plus either operation of 11% of existing generation not expected to be on-line or load relief from 2% of industrial load in the area.

Figure 5: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Optimistic Assumptions)



2.5 Report Organization

In Section 3 of this report we discuss the analysis methods that we have employed in the economic screen of alternatives to the KEL line. This screen is a forward-looking economic analysis that uses the benefit/cost (B/C) ratio of alternatives as the primary indicator of cost-effective solutions. A B/C ratio greater than one indicates that the benefit of a non-transmission alternative is greater than its cost, and therefore it is a potentially cost-effective alternative to the transmission line. One of the primary benefits of line deferral to TBL and their ratepayers is the reduction in TBL's future revenue requirement that can be achieved by a deferral of the line.

As described in Section 4, the first step of our analysis is an investigation of area load growth and the duration and level of projected overloads. This is fundamental to our study as it shows us when and at what level demand reduction is required from the non-wires alternatives.

Next we conducted a simple evaluation using base-case assumptions about the cost-effectiveness of non-wires options to allow TBL to look at as wide a set of alternatives as possible. The technologies and programs that we included in the economic screen are described in Section 5. We describe the results of the base case analysis in Section 6.

Finally we applied scenario analysis (described in Section 7), and benchmarking techniques to estimate the market penetration potential for promising alternative (described in Section 8) to develop a more robust picture of the alternatives.

Section 3. Methodology

We screened for cost-effective alternatives by calculating the benefit/cost (B/C) ratios for a variety of non-wires technologies and programs. A B/C ratio greater than one indicates that the non-wires alternative has a benefit greater than its cost, and therefore is a potentially cost-effective alternative to the transmission line. Suggesting that a measure is "cost-effective" however, immediately raises the question, "cost effective to whom?"

If TBL's goal is to resolve transmission problems at the lowest cost to its ratepayers, the appropriate B/C measure for TBL is the Ratepayer Impact Measure (RIM test), which measures the impact on TBL's rates. The benefits include the change in BPA-TBL's revenue requirement that can be achieved by the deferral of the KEL transmission line (or other wires) investment. The costs included in the RIM test are the direct program costs that will be included in the revenue requirement (i.e., incentive payments paid by TBL to the providers of the non-wires solution(s) to the transmission problem and TBL's administrative costs) and TBL's lost revenues due to reduced sales. Lost revenues are included in the RIM test because these lost revenues are collected from remaining sales thereby increasing the per unit rate. If a non-wires alternative's RIM-B/C ratio is greater than one (1.00), then this alternative would tend to decrease per unit rates that TBL would charge to collect its revenue requirement. The potential "savings" from lower the revenue requirement can be used to "buy" a non-wires alternative.[5]

Measures that do not pass the RIM test could be used if they pass the TRC or the Distribution Utility RIM test. However, this would increase TBL's revenue requirement relative to building the line. There are three basic options for dealing with the increased revenue requirement. First, the additional cost could be borne by TBL's transmission ratepayers. Second, the additional cost could be spread across all of BPA's rates. Third, the additional cost could be reflected in the rates of distribution utility customers. These are institutional and policy considerations that are beyond the scope of this analysis and will require more time for resolution than is available relative to the KEL line decision process.

There are competing views of the appropriate criterion for cost-effectiveness. The principal debate is between the Ratepayer Impact Measure (RIM) and the Total Resource Cost test (TRC). RIM compares the effect on TBL's rates of the cost of alternatives versus the capital and maintenance costs of a proposed solution. TRC compares the costs and benefits of alternatives with all the costs and benefits of a proposed solution. TRC includes energy and generation benefits. An alternative deemed cost effective under TRC could cause rates to be higher. While our analysis provides information to use in evaluating these two criteria, it was not intended to provide guidance as to the appropriateness of one over the other.

3.1 Cost-Effectiveness Tests

TBL's ratepayers are not the only stakeholders in a transmission line expansion. We also evaluate cost-effectiveness from a number of different perspectives: Total resource cost, societal, participant, and local utility. The purpose of including all perspectives is to find solutions that are

---

[5] A deferral of a wires investment that resulted in increased O&M costs could potentially increase the revenue requirement

cost-effective or "winners" for all stakeholders. Looking at all perspectives also aids in program design. For example, one of the costs for the RIM test is the incentive paid by TBL to the provider of the non-wires solution, which could be the contractual payments to a local generator to be available to operate during the heavy load hours or to an industrial customer to curtail their load during such hours. A win-win program design is one that would set the incentive level payment such that both TBL's ratepayers and the program participant are better off, i.e., the RIM and Participant B/C ratios are both greater than one. If we can find such a balance, this is a program that warrants further investigation as a potential alternative to the transmission line.

Table 2 outlines the program costs and program benefits that are attributed to cost test perspective, which are described below.

Table 2: Costs & Benefits for Each B/C Test Perspective

Tests and Perspective	Program Costs	Program Benefits
RIM Test **BPA TBL**	TBL Incentive TBL Revenue Loss Admin Costs	T Avoided Cost
Utility Cost Test **BPA TBL**	TBL Incentive Admin Costs	T Avoided Cost
TRC Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings	Gen Capacity Savings Energy Savings T Avoided Cost D Avoided Cost
Societal Cost Test	Measure / Program Costs Admin Costs Avoided Loss Savings Environmental Externalities	Gen Capacity Savings Energy Savings T Avoided Cost D Avoided Cost
Participant Cost Test **Distribution Utility Customers**	Participant Measure / Program Costs	TBL Incentive Dist. Utility Incentive Dist. Revenue Loss
RIM Test **Distribution Utility**	Dist. Utility Incentive Dist. Revenue Loss Utility Admin	Gen Capacity Savings Energy Savings TBL Revenue Loss D Avoided Cost

3.1.1 Ratepayer Impact Measure (RIM) - Transmission Company

This benefit/cost test measures the impacts on TBL's rates. The benefits included are the transmission cost savings from the deferral of the line and changes in O&M costs. The costs included are the incentive payments paid by TBL to the providers of the non-wires solution(s), TBL's administrative costs, and TBL's lost revenues due to reduced sales. If the program benefit/cost ratio is less than one, this program would tend to increase the per unit rates that TBL would charge to collect its revenue requirement. Measures that have a high reduction in sales relative to peak load reductions, such as conservation, are generally not cost-effective from the RIM perspective.

3.1.2 Utility Cost Test - Transmission Company

This test measures the impacts on BPA's revenue requirement. The benefits included for this test are the transmission avoided costs including O&M savings. The costs included are the TBL incentive payments and TBL administrative costs. If the program benefit/cost ratio is less than one, the program will increase the revenue requirement. This test is different than the RIM test because the lost sales due to any measures that reduce BPA sales will generally not alter the transmission company revenue requirement.

3.1.3 Total Resource Cost Test (TRC)

The TRC test measures the costs and benefits from a broader perspective and includes all of the direct cash costs associated with the non-wires alternative. The benefits include the avoided costs of transmission, distribution, generation capacity and energy, including losses. The costs include the lifecycle costs of the measure, O&M costs, program administrative costs, and the lost opportunity to realize a reduction in transmission losses from building the line. Transfers such as incentive payments between BPA and its customers, as well as bill savings, are not included from this perspective since the net cost of transfers between BPA and customers is zero.

3.1.4 Societal Cost Test

The societal cost test includes the broadest set of costs and benefits. In addition to the direct cash costs accounted for in the TRC test, any environmental externalities such as reduced air emissions are included as a benefit.

3.1.5 Participant Cost Test

The participant cost test measures the lifecycle net benefits for the participant. The participant is the customer that installs the DSM, curtails their load, or owns the DG. The benefits included in this test are the incentives paid to the customer and the customer's bill savings due to the measure. The costs included are the life-cycle costs of the measure to the participant. This cost test is a good indicator of how acceptable a program will be to individual customers who might participate in the program.

3.1.6 Ratepayer Impact Measure (RIM) - Distribution Company

This benefit/cost test measures the impacts on the rates of the distribution utilities that BPA TBL serves with their transmission system. The benefits included for this test are the transmission avoided costs, and the costs included are the incentive payments paid by the utility to the providers of the non-wires solution(s) to the transmission problem, the utility's administrative costs and the utility's lost revenues due to reduced sales. If the program benefit/cost ratio is less than one, this program would tend to increase the per unit rates that the utility charges to meet its revenue requirement. Measures that significantly reduce sales relative to peak demand reductions, such as conservation, generally are not cost-effective from the RIM perspective.

3.2 Transmission Avoided Cost Definition

As we state above, the basic benefits of non-traditional alternatives on the transmission system are measured as the change in BPA-TBL's revenue requirement that can be achieved by the deferral of the KEL transmission line (or other wires) investment. In calculating the avoided costs of this project, we are estimating the forward-looking incremental cost of building the KEL line. If this transmission line can be avoided or deferred for a year or longer, then this will result in a reduction of TBL's future revenue requirements. The avoided transmission cost is just one component of the total system benefits of implementing an alternative solution; however, from the BPA-TBL perspective, it is the only benefit of reducing peak loads. Therefore, we focus in this section on the calculation of the transmission avoided cost component; however the method is similar for the other components of avoided cost.[6]

This method of calculating the long run incremental costs is also referred to as the 'differential revenue requirement' method because it is based on the difference in revenue requirements before and after deferral of the transmission project.

Step 1: Estimate the Revenue Requirement and Timing of the Planned Transmission Investment.

Table 3 shows the revenue requirements for the planned KEL transmission line project. The costs are shown at revenue requirement levels (direct investment dollars have been scaled up to account for administrative and general costs, debt repayment, tax effects, and operations and maintenance expenses) so that the economic savings to the BPA rate base can be estimated.

Table 3: Revenue Requirement of Planned Expenditures

A	*B*	*C*	*D*	*E*
Year	Investment	Constant Base Year Dollars ($1000s)	Base Year	Revenue Requirement in Nominal Dollars ($1000s)
Investment data from BPA				
2002				
2003	KEL Y1	25,000	2003	25,000
2004			2004	0

Step 2: Evaluate the Load Reduction Required on the Transmission Path to Defer the Project

Table 4 shows the forecast of load reduction requirements on the Covington transformers based on the needs assessment described later in Section 4. If this amount of load reduction can be achieved during the critical load periods, BPA-TBL can maintain its system reliability criteria and defer the project. Note that the actual amount of load reduction required is several times greater than the Covington transformers' overload due to the way that power flows over the transmission network. (See Section 4.4).

The base case load scenarios in this analysis identify a need for 122 MW of load reduction at the Covington transformers in the winter of 2003/2004 in order to defer the KEL transmission line.

6 For more detail, see *Costing Methodology for Electric Distribution System Planning*, prepared by E3 and Fred Gordon of Pacific Energy Associates for the Energy Foundation.

The method the team employed to arrive at this initial base case load reduction target is described in Section 4.

Table 4: Overload of the Covington Transformers

A	*B*
Year	Peak Load Reduction Required (MW)
2002	-
2003	122
2004	190
2005	269
2006	397
2007	449
2008	505
2009	558
2010	611
2011	664
2012	714
2013	766
2014	818
2015	870

Step 3: Calculate the Change in Revenue Requirement per kW of Load Reduction

Table 5 shows the calculation of the reduction in revenue requirement from postponing the KEL transmission line project if the alternatives can achieve the required amount of load reduction.[7] Column A shows the revenue requirement of the expenditures (from Table 3). Column B is the required annual load reduction from Table 4. Column C shows the assumed amount of load reduction, which has been set to equal the annual load growth from 2002/3 to 2014/15.

The assumption on the amount of load reduction is important but subtle. We are estimating the value of load reduction at the constrained location for a **meaningful** decrement of load[8]. Column D shows the deferral length in years achieved by the load reductions in column C. This deferral length can vary by year depending on the load growth in each year. Column E shows the value of the deferral for each year. The deferral value is calculated as the difference in the present value of revenue requirement under the original and deferred schedule. [9]

[7] This load reduction could be due to distributed generation, curtailable load, DSM or other strategy.

[8] For systems that have a radial configuration, the amount of load reduction at the constraint will be the same as the total resource that is implemented (adjusted for losses). In network systems, flow distribution factors can be used to estimate load reduction achieved at the constraint from a reduction at a particular point on the system.

[9] The inflation rate and weighted average cost of capital (WACC) used in the calculation of Column E are 2.7% and 9%, respectively.

The method for calculating the deferral value is based on the concept that the value of a load change is equal to the difference between the present value of the original investment plan and the present value of the deferred plan.[10] The cost of a deferred investment increases with the inflation rate but decreases by the cost of capital (discount rate). Since the discount rate is higher than the inflation rate, this results in a net present value savings:

Deferral Value = Nominal Cost in Year(i) × (1 – ((1+*Inflation Rate*)/(1+*Discount Rate*))^Δt)

Where Δt is the deferral length in years.

For example, the 122 MW of load reduction prior to 2003 results in a savings of $1.445 million dollars in TBL's revenue requirement.

Table 5: Calculation of Transmission Deferral Value at Covington

	A	*B*	*C*	*D*	*E*	*F*
Year	Scaled Nominal Cost ($000)	Incremental Load Reduction Required (MW)	Load Reduction (MW)	Deferral Length (yrs)	Deferral Value ($000)	Marginal Cost ($/kW)
	(see prior table)			*(Col C / Col B)*	*(A * (1-((1+inflation)/(1+WACC))^D))*	*(Col E / Col D)*
2003	25,000	122.0	122.0	1.00	1,445	11.84
2004	0	67.9	67.9	1.00	0	0.00
2005	0	79.3	79.3	1.00	0	0.00
2006	0	128.0	128.0	1.00	0	0.00
2007	0	52.2	52.2	1.00	0	0.00
2008	0	55.3	55.3	1.00	0	0.00
2009	0	53.5	53.5	1.00	0	0.00
2010	0	52.9	52.9	1.00	0	0.00
2011	0	52.6	52.6	1.00	0	0.00
2012	0	50.2	50.2	1.00	0	0.00
2013	0	52.0	52.0	1.00	0	0.00
2014	0	52.0	52.0	1.00	0	0.00
2015	0	52.0	52.0	1.00	0	0.00

Step 4: Adjust for Changes in O&M Costs

The avoided O&M costs associated with deferring the KEL transmission line are added to the total deferral value prior to calculating the total transmission marginal cost in $/kW. For example in this base case scenario the avoided O&M costs of $50,000 are added to the $1.445 million dollars calculated in Column F to yield an adjusted total deferral value of $1.495 million. When the total deferral value is divided by the amount of load reduction required, we get the value per kW of load reduction. In the base case scenario this gives us a marginal cost of $12.25/kW in 2003. This means that each kW of the 122 MW of total reduction in 2003 is worth $12.25/kW because of the value of deferring the expenditures in that year. However, this value only holds if

[10] See Area Specific Marginal Costing for Electric Utilities: "A Case Study of Transmission and Distribution Costs", R. Orans Ph.D. Dissertation, 1989.

the full 122 MW of load reduction is achieved. If the load reduction is less than 122 MW, then the value equals zero.

Step 5: Calculate the Total Transmission Avoided Costs

These calculations suggest that the maximum that BPA –TBL could pay without increasing the revenue requirement is $12.25/kW for a program that cut demand by 122 MW in 2003. Table 6 shows the value of additional load reduction to achieve additional years of deferral.

Table 6: Base Case Incentive Levels Using $25M Dollar Avoided Investment Cost

Minimum Contract Length	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year
Minimum Total MW Required	122.00	189.93	269.20	397.20	449.39	504.73	558.19
Maximum Incentive	$ 1,494,954	$ 2,906,393	$ 4,236,252	$ 5,489,249	$ 6,669,824	$ 7,782,165	$ 8,830,214
$/kW (PV Contract Payments)	$ 12.25	$ 15.30	$ 15.74	$ 13.82	$ 14.84	$ 15.42	$ 15.82
$/kW-yr (Level Annual Payments)	$ 12.25	$ 7.98	$ 5.70	$ 3.91	$ 3.50	$ 3.15	$ 2.88

This equates to a total value of $1,494,954 that would be economical to offer in order to achieve the required load reduction for one year. Looking out into future years, on average, there would be a maximum of approximately $1 million dollars of avoided costs per year available for programs or technologies to defer the transmission line investment. For each consecutive year after the initial expenditure would be made, the incentive level in present value terms is discounted further because the inflation rate is lower than the discount rate.

3.3 Avoided Loss Savings

With the addition of the KEL line, TBL estimates line losses will be reduced by approximately 48,180MWh per year due to improvements in the efficiency of the transmission system. This estimate is based on 11MW peak loss savings, and a loss factor of 50%. The loss factor measures the relationship between peak losses to average annual losses. Therefore, 11MW at a 50% loss factor implies 5.5aMW per year, or 48,180MWh per year.

The KEL line provides significant energy savings. Using the market price forecast developed in this study that shows a long-run marginal cost of electricity of $40.03/MWh, the reduction in losses attributable to the construction of the KEL line results in an annual savings to transmission users of approximately $1,928,645 per year of energy that would not have to be generated.

The team analyzed the unattained loss savings as one of the costs of deferring the line from the TRC and Societal cost test perspectives. For consistency of terminology, we refer to this foregone loss savings as “avoided loss savings.” For each year that the line is not built, the transmission system does not gain from the efficiency improvements the KEL line would provide. This cost is offset by the financing benefit of deferring the line and the team calculated the avoided line loss savings with an approach very similar to the transmission avoided costs described in Section 3.2. The same calculation is made as described in the transmission avoided costs except that instead of a benefit of approximately $1,400,000 per year of deferral, the avoided line loss savings is treated as a cost of approximately $2,000,000. The energy savings from the reduction in losses if the KEL line is built is greater than the benefit of deferring the line.

Table 7 shows the avoided loss savings from deferral of the KEL line on a per kW-year basis for a 3, 5, and 10-year deferral of the line. For each kW of load reduction at Covington substation that a transmission alternative achieves, the share of avoided line loss savings per kW is added as a cost of the program. For example, if the line is deferred for 3 years, the cost in avoided loss savings is $7.34/kW-year.

Table 7: Avoided Loss Savings from Deferral of the KEL Line

Deferral Length	3 Years	5 Years	10 Years
Avoided Losses ($/kW-year at Covington)	$ 7.34	$ 4.51	$ 2.99

Not all of the stakeholders benefit from a reduction in losses on the system. Most notably, a change in losses does not impact the BPA TBL revenue requirement or transmission rates since the losses on the system are collected directly from transmission users, and not through rates. Therefore, from the TBL RIM perspective avoided loss savings are not included.

From a distribution utility RIM perspective, a reduction in losses would be a benefit since lower losses would lower the price of purchased energy on the system. However, since losses are paid on a system average basis by all transmission users for all sales, the 5.5aMW change compared to the total losses on the system would have an extremely small impact on the price for energy and therefore the avoided line loss savings is ignored from the distribution utility RIM perspective.

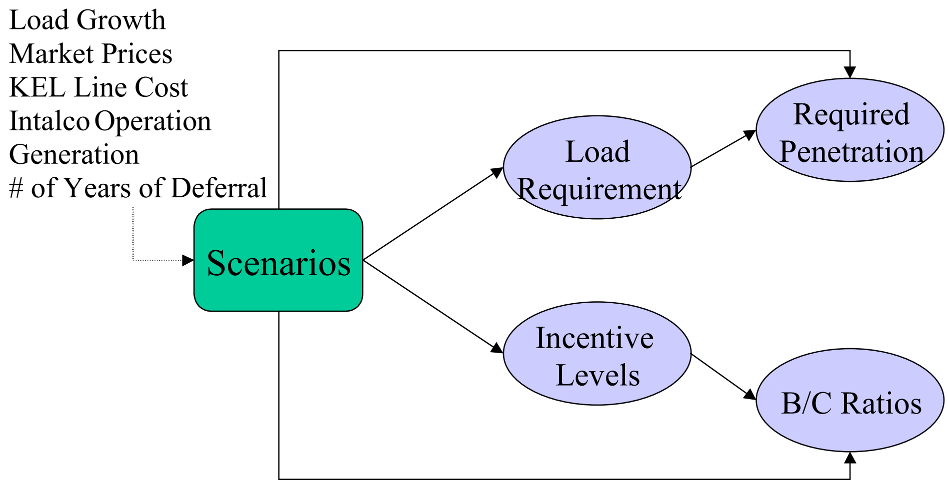
From a participant perspective installing a distributed generator, or energy efficiency, the impact of the avoided line losses is also too small to be significant. The cost of energy for the participant is based on the utility tariff that will not change significantly due to the avoided KEL line losses.

The team did include the avoided line loss savings in the calculation of the Total Resource Cost (TRC) and Societal Cost tests since the region would save these losses if the KEL line were built.

3.4 Scenario Analysis

In the base case analysis we include assumptions about: future market prices for electric energy; the cost of the KEL line; load growth in the Puget Sound area; the amount of generation operating in the area; the years of deferral that can be achieved for the KEL line; and the likely participation of large industrial customers in load control programs. These are all uncertain variables and different assumptions about these variables will alter the cost-effectiveness of non-wires alternatives to the KEL line. Referring to Figure 6 we see how these uncertain variables influence load requirement and incentive levels, which in turn impact the required market penetration from cost effective measures and the results of the B/C tests. For example, if we assume high market prices for the years 2003 and 2004 then merchant generation plants are more likely to be built independently of TBL incentives, thereby lowering the potential overload on the Covington transformer banks and resulting in higher incentives that can be applied to “buying” other solutions for the remaining overload problem. Therefore, as part of the analysis we also consider a range of possible scenarios for the Puget Sound area. We present the results of the scenario analysis in Section 7.

Figure 6: Overview of the Scenario Analysis



3.5 Program Benchmarking

In order to ascertain what are reasonable assumptions for the implementation of Demand Reduction/Direct Load Control (DR/DLC) programs, the team conducted a benchmarking survey of relevant utility programs. BPA provided the team with a draft research report on demand response programs that was used as the primary source of pertinent program information.[11] In addition to this source, we obtained supplemental DR/DLC program information through an extensive search of utility websites and the Energy Information Administration's publicly available database.[12] For confidentiality reasons, the specific names of the utilities conducting DR/DLC programs are not provided in this report.

In total, the team collected program information from 19 different programs that were targeted to industrial and/or commercial customers and operated by utilities throughout the United States. We did not include residential demand response programs in this analysis because these types of programs are not consistent with the high level of reduction that BPA would need to achieve in an extremely short time period. Given a longer implementation timeline, BPA could potentially leverage or support its utilities' load reduction programs within a more dispersed customer segment.

The team collected data on the pricing (incentive level), duration (hours, months, and years), and energy (MW) either reduced, or available for demand reduction, for each of the 19 programs. We applied this information in two analyses. First, we included the pricing levels and duration of each program in our cost/benefit analysis to determine whether similar programs would yield a favorable result (more benefits than costs) from the ratepayer's perspective if a particular program was implemented. Second, we included information regarding the level of load reduction that is available under each program and applied these levels in our penetration analysis discussed below.

[11] "BPA Demand Response Program Research Report" Xenergy, Inc. September 2002, DRAFT, pp. 1-124.
[12] Energy Information Administration website: www.eia.doe.gov

3.6 Penetration Analysis

The team conducted a penetration analysis to gauge what level of penetration is achievable at varying incentive payment levels. We measured levels of penetration as the percentage of MW reduced within the targeted segment. In order to do this, we compared programs with fixed incentive levels with the total MW subscribed or committed for reduction at the incentive level offered. We converted the total MW into a percentage of utility demand in the commercial/industrial sector to get an appropriate penetration level percentage. While overall penetration targets established by the utility managing the program are not included in this analysis, the results provide a clear view as to the feasible range for DR/DLC programs. The results of this analysis are described in Section 8.

Section 4. Area Load Growth Factors and Implications

In order to conduct an effective screening process for potential alternatives to the construction of the KEL transmission line, it is important to understand the characteristics of the Puget Sound Area electrical system that contribute to the need for the additional capacity. The need for the KEL Transmission Project derives from projected overloads that could arise during the winter of 2003-2004 if a transmission outage occurs during a 1-in-20 year ‘Arctic Express’ weather event.

TBL projects loadings on critical transmission system elements by aggregating load growth forecasts submitted by large utilities in the area, developing forecasts for the smaller utilities and adding transmission contracts with Direct Service Industries (DSIs). The team used these projections in conjunction with load duration curves from historical years in which extreme cold weather events occurred to develop capacity and duration targets for transmission alternatives.

4.1 Determinants of Peak Demand Forecast

The projected overload results from a variety of factors, including projected growth of peak loads in the Puget Sound area, power delivery obligations to Canada under the Columbia River Treaty, assumptions about system conditions such as the operation of local generators, and a projection of the effect of extremely cold weather on Puget Sound area peak loads. These factors serve as inputs to a load flow analysis that projects the loadings on the critical elements under various system contingencies such as generator or transmission line outages. If the projected loadings under certain contingencies exceed equipment ratings, BPA must take action to avoid being in violation of WECC reliability criteria.

4.1.1 Utility Load Forecasts

For large utilities, including investor-owned utilities and larger public utilities, BPA requests “average” (i.e., 50% probability of being higher or lower) forecasts of peak demand. These forecasts are accepted as submitted. The loads of smaller publicly owned utilities are forecast by BPA Transmission and added to the large utility forecasts. BPA then adjusts these forecasts to reflect 1-in-20 year “extreme cold” or heavy load conditions with factors developed by the larger utilities or by BPA. Utility peak loads are assumed to be coincident, based on an ‘Arctic Express’ weather event.

4.1.2 Direct Service Industries (DSIs)

DSIs are industrial customers, such as aluminum smelters, that take transmission service directly from BPA. They are generally served on a contract demand basis, meaning they have a right to use transmission up to the contracted amount. For these customers, BPA assumes that peak load is equal to 100% of contract demand. Currently, there is only one large DSI operating in the Puget Sound area. Intalco, an aluminum smelter located in Ferndale, Whatcom County, has a transmission contract for 468 MW.[13]

---

[13] Kaiser Aluminum, in Tacoma, previously had an historical peak load of 152 MW, but currently has no firm transmission contract with BPA.

4.1.3 Canadian Entitlement

Another source of demand for transmission in the Puget Sound area is the return of the "Canadian Entitlement", an obligation to deliver energy and capacity to Canada that stems from the Columbia River Treaty. The Canadian Entitlement is calculated annually according to the terms of the Treaty and subsequent implementation agreements. BPA returned a maximum of 600MW in 2002, and expects to return 907 MW of capacity in 2004, increasing to 1,179MW in 2007.

4.1.4 Local Generation

One factor that can *reduce* transmission demand is the amount of local generation that is operating. There are approximately 2,500MW of generating capacity in the Puget Sound area north of Tacoma. Approximately 60% of this capacity, or 1,600MW, is gas-fired thermal generation. Most of the thermal generation is composed either of peaking plants owned and operated by Puget Sound Energy (800MW) or industrial cogeneration (700MW). The remainder is largely hydroelectric. Large hydro projects include Seattle City Light's Skagit River projects (650MW), Puget Sound Energy's Baker River projects (162MW), and Snohomish PUD's Henry M. Jackson project on the Sultan River (112MW).

BPA's load flow studies assume that most generation in the area, some 2000 MW, is running at or near maximum capacity. The team used this level of generation operating as a baseline for incorporation into the study of alternatives. However, there are a few plants that may have additional generating capacity beyond what BPA is assuming, capacity that potentially could be enlisted to defer the Kangley-Echo Lake line if gas is available. The impact of additional available generation is discussed in the Penetration Analysis Section 8.

4.2 Projected Overloads and Alternatives Targets

4.2.1 Load Flow Analysis

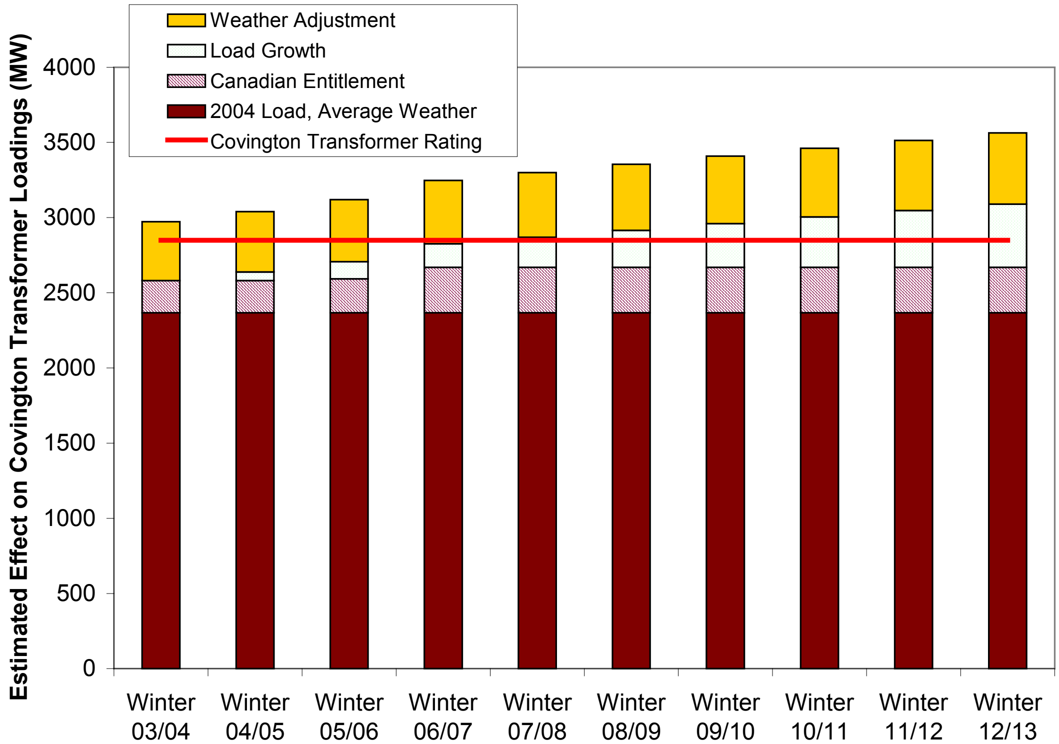
BPA uses local load and resource forecasts as inputs to a load flow analysis, which is a computer model that projects loadings on critical elements under a variety of contingency conditions. BPA studies show that, under certain contingencies, overloads can occur on a variety of elements in the Puget Sound area, including two 500 kV transformer banks at BPA's Covington substation near Enumclaw, the Covington-Creston and Covington-Duwamish 230 kV circuits, and Tacoma Power's 115 kV system. At the direction of BPA, the team focused on the loadings on the Covington transformer banks. Transmission alternatives that reduce loadings on the transformer banks below the limit will also prevent outages on the other elements. The Covington transformers have a combined emergency rating of 2,850 MVA. BPA conducted load flow studies for heavy load conditions in winter 2003/2004, and concluded that an outage would cause an overload of 122 MVA on the transformer banks (See Table 8.).

Table 8: Projected 2004 Overload on Covington 500 kV Transformers

Inputs	
Total Utility Load (MW)	11,149
Direct-Service Industry Load (MW)	468
Exports under Canadian Entitlement (MW)	907
Total Local Generation (MW)	2,036
Results	
Covington Transformer Bank Loading, Outage Case (MVA)	2,972
Covington Transformer Rating (MVA)	2,850
Overload (MVA)	122

Figure 7 presents a graphical view of the factors that contribute to the need for the Kangley-Echo Lake Transmission Project. Forecasts of 2004 utility average weather (1-in-2 year) peak loads would contribute approximately 2,350 MW of loading to the Covington transformer banks, in the event of an outage. Return of the Canadian Entitlement adds 215 MW in 2004, while adjustment of utility forecasts to reflect 1-in-20 year severe weather conditions adds another 390 MW. As loads grow in the years after 2004, the need for the line becomes more pronounced. The average annual growth forecasted for the Puget Sound Area for 'normal weather' over the next 10 years equals 1.5% or 173 MW. By 2008, the combination of load growth and increases in the Canadian Entitlement return mean that new capacity is needed to serve peak loads during an average weather year.

Figure 7: Factors Contributing to the Need for the Kangley-Echo Lake Project



4.2.2 Targets for Alternatives

To identify load reduction targets, the team projected Covington transformer loadings based upon BPA's forecast. Our results are portrayed graphically in the charts below. Overloads are projected for every year after 2004, jumping in 2007 with the next installment of the Canadian Entitlement, and growing steadily thereafter. By 2010, the potential overload reaches nearly 600 MW.

The projected peak loadings and the annual load shapes provide the criteria that define success for transmission alternatives. In order to be successful, a transmission alternative must be able to supply the needed capacity to the system at the appropriate time. The maximum capacity needed in a given year is the highest projected overload in that year, based on the 1-in-20 year adjustment to utility load forecasts described above. However, not all overload hours require that much capacity.

The shape of the load curve is a critical parameter for the success of transmission alternatives. Unfortunately, the shape cannot be known with any certainty in advance. The most appropriate load shape is the one that best reflects the conditions that are likely to occur during a year with a 1-in-20 year event, since this is the event that leads to the maximum loadings the transmission system must be planned to accommodate. Such a year is likely to have a somewhat lower load factor than a normal year, as the peak loads will be relatively higher regardless of the level of the base load. Based on feedback from BPA, the team developed a load shape using a combination of the 1988-89 and 1990-91 winter seasons.

Figure 8 presents projected overloads in 2004 and 2010 based on this load curve and the load forecasts described above. Based on this load shape, 2004 is projected to have 10 hours in which an outage would lead to an overload on the Covington transformer bank. By 2010, an overload could occur for 86 hours.

Figure 8: Projected Post-Contingency Loadings on Covington Transformer Banks

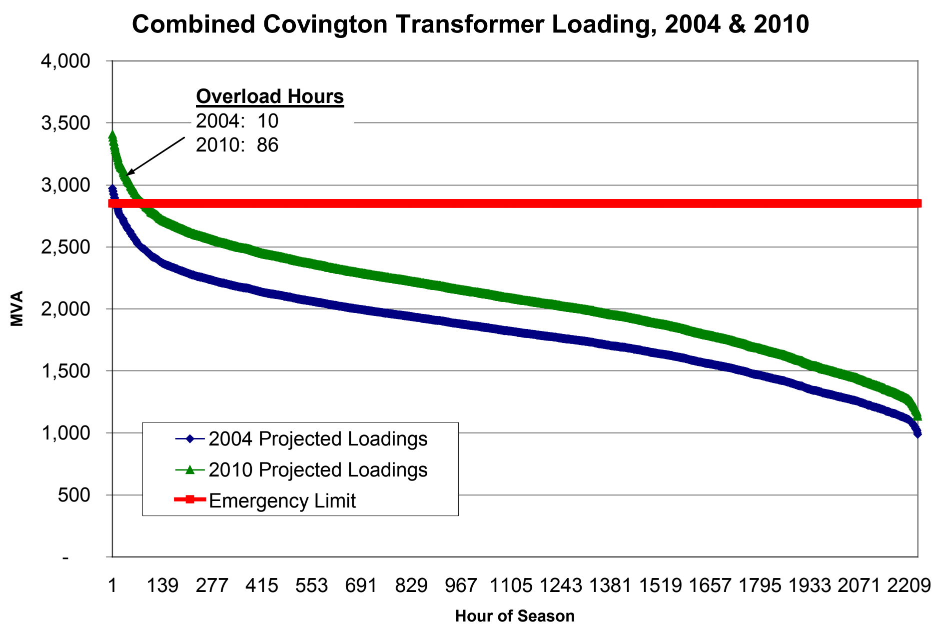


Figure 9 and Figure 10 present another view of the projected overloads. These figures depict a vertical view of a three-dimensional surface in which the horizontal axis is days of the year, from the 1990-91 season,[14] the vertical axis is hours of the day, and the Covington transformer loadings are indicated by the color on the figure. In these figures, the red area represents overload conditions (transformer bank loadings above 2,850 MVA) and the orange area represents hours of concern (loadings between 2,350 and 2,850 MVA). The 2004 overloads occur only during the December 19-23 period that featured the 1990 'Arctic Express' event. There are only scattered periods in which loadings creep over 2,350 MVA. By 2010, the period in which post-contingency loadings exceeds 2350 MW encompasses nearly all the daytime hours from mid-December to mid-January. The mid-December overloads have extended to a week, and overloads appear during several other morning and evening peak periods.

[14] For illustrative purposes, the ordered hours from the load curve constructed by the team are collated with the hours from 1990-91, so that the highest load hour from the constructed curve occurs on the same day and hour as the highest load hour from the 1990-91 season, the second-highest load hour occurs on the same day and hour as the second-highest load from 1990-91, etc. Thus, the overloads can be shown occurring in their natural pattern, i.e., in an extreme cold weather event that lasts for several days. Whether such an event will occur in December, January or February, of course, cannot be known in advance.

Figure 9: 2004 Covington Transformer Bank Loadings by Day and Hour

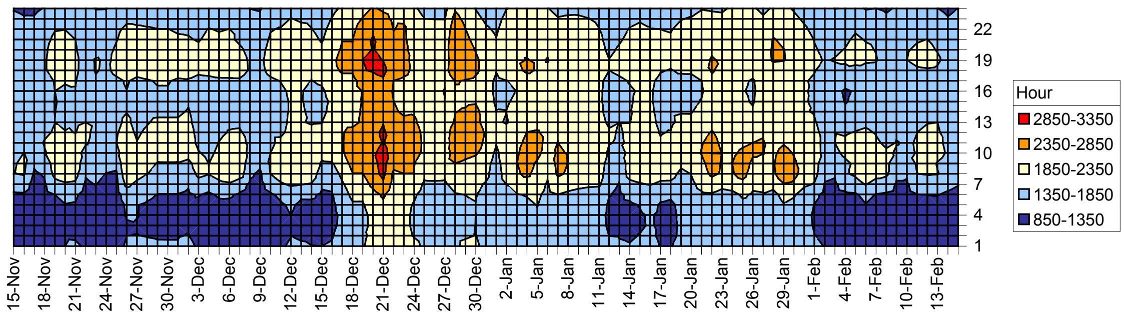
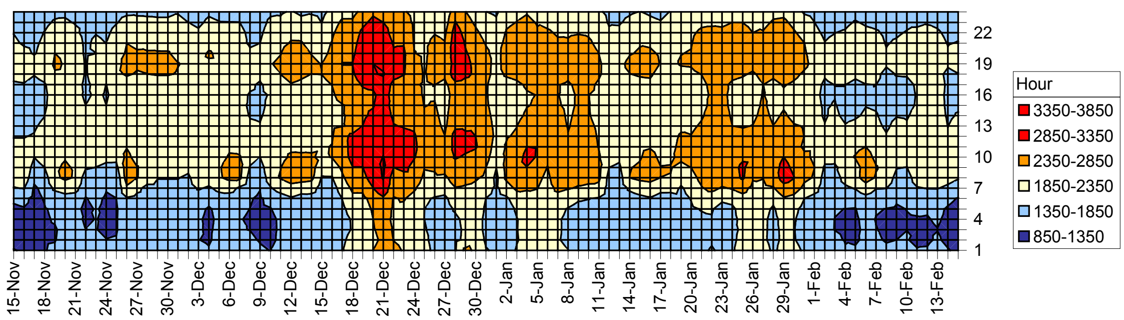


Figure 10: 2010 Covington Transformer Bank Loadings by Day and Hour

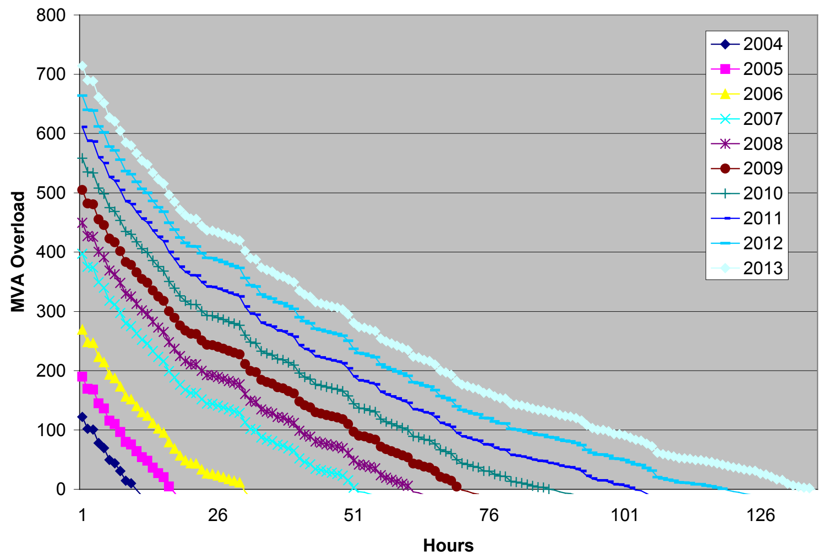


The maximum capacity targets, and the number of hours in which capacity is needed, are presented in the following table. Table 9 shows the projected overloads in 2004 and 2010 by hour of the day. In 2004, overloads occur variably during the 6 AM to 10 PM peak period. As expected, more overloads occur during the late morning and early evening periods. By 2010, overloads occur on 11 days during the 10 AM hour and 9 days during the 6 PM hour.

Table 9: Projected Transformer Bank Overloads by Hour of Day, 2004 and 2010

Hour of Day	2004	2010
12:00 – 5:59 AM	0	0
6:00 – 6:59 AM	0	1
7:00 – 7:59 AM	1	5
8:00 – 8:59 AM	1	6
9:00 – 9:59 AM	1	10
10:00 – 10:59 AM	1	11
11:00 – 11:59 AM	1	9
12:00 – 12:59 PM	0	4
1:00 – 1:59 PM	0	2
2:00 – 2:59 PM	0	1
3:00 – 3:59 PM	0	1
4:00 – 4:59 PM	0	3
5:00 – 5:59 PM	2	7
6:00 – 6:59 PM	1	9
7:00 – 7:59 PM	1	7
8:00 – 8:59 PM	1	4
9:00 – 9:59 PM	0	4
10:00 – 10:59 PM	0	2
11:00 – 11:59 PM	0	0
Total Overload Hours	*10*	*86*

Figure 11: Transmission Alternative Targets, 2004-2013



4.3 Other Factors Affecting Projected Overloads

The potential for deferral of the KEL line is driven by the forecasted need to meet system overloads. However, the factors that determine the overall load in the Puget Sound Area have elements of uncertainty and variation. Factors that have an effect on area load estimates and, thus potential alternatives to KEL line construction include the Canadian Entitlement return and the sensitivity to the adjustments made for weather. The relevant issues around these factors are described below.

4.3.1 Canadian Entitlement Return

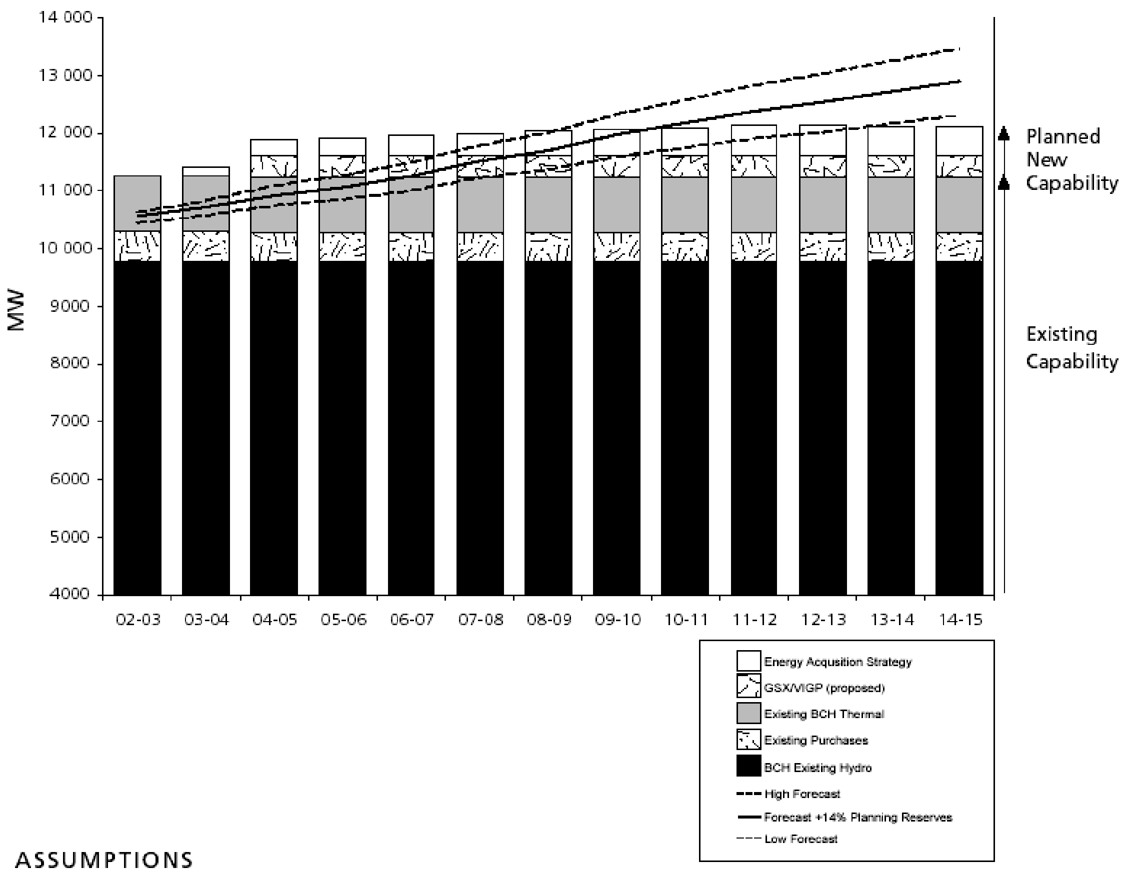
The return of the Canadian Entitlement comprises approximately 7.5% of the total projected loading on the Covington transformer banks in 2004, rising to 10% in 2007. While the Canadian Entitlement is clearly a significant contributor to the need for the KEL transmission line, Puget Sound area load growth would require new transmission by 2006 even without the Entitlement.

Canadian Entitlement power is delivered to the British Columbia Hydro and Power Authority (BC Hydro). BC Hydro is a Crown Corporation acting as the agent of the government of Canada in implementing the terms of the Columbia River Treaty, much as BPA acts as the agent for the United States. Under the original terms of the treaty, Entitlement power was to be returned to Canada at the border near Oliver, in the Okanogan Valley. As BPA and BC Hydro negotiated the implementation of the Entitlement in the late 1990s, an agreement was reached instead to deliver the power to Canada over the existing 500 kV system in Puget Sound area and the existing 230 kV system near Boundary Dam in eastern Washington.

BPA treats power deliveries to Canada under the terms of the treaty as a firm transmission obligation, just as it does deliveries to loads in the United States. Like U.S. utilities, BC Hydro relies on the firm power and transmission capacity that BPA is providing to meet peak loads on its own system.

While BC Hydro may request the power to be delivered elsewhere in the United States, the power is generally being used to serve load on BC Hydro's system during winter peaks. BC Hydro is currently very close to supply-demand balance. At expected rates of growth, BC Hydro will need new resources beyond existing generation and purchases by 2006. Figure 12 portrays BC Hydro's projected supply-demand balance through 2014.

Figure 12: Demand and Supply Balance for BC Hydro



(Source: BC Hydro's 2002 Annual Report)

4.3.2 Weather Sensitivities

As described above, utilities provide BPA with "average" winter peak loads, i.e., peak loads that would be expected in an average weather year. BPA then adjusts these loads upward to reflect a 1-in-20 year 'Arctic Express' weather event, using adjustment factors either provided by the utilities or based on a study done by Battelle for BPA. The adjustment factor is different for each utility, depending on the types of loads in each utility's service territory, and changes with the composition of loads during the forecast period. The adjustment factor averages approximately 17%.

In order to determine how sensitive the need for the project is to this parameter, the team calculated the maximum weather sensitivity factor that would avoid an overload during each year of the forecast period. The results are presented in Table 10.

Table 10: Maximum Weather Adjustment Factors to Avoid Overload

	2004	2005	2006	2007	2008	2009
Average Year Load	2,582	2,626	2,681	2,791	2,825	2,861
Rating	2,850	2,850	2,850	2,850	2,850	2,850
Maximum Adjustment	10.4%	8.5%	6.3%	2.1%	0.9%	-0.4%

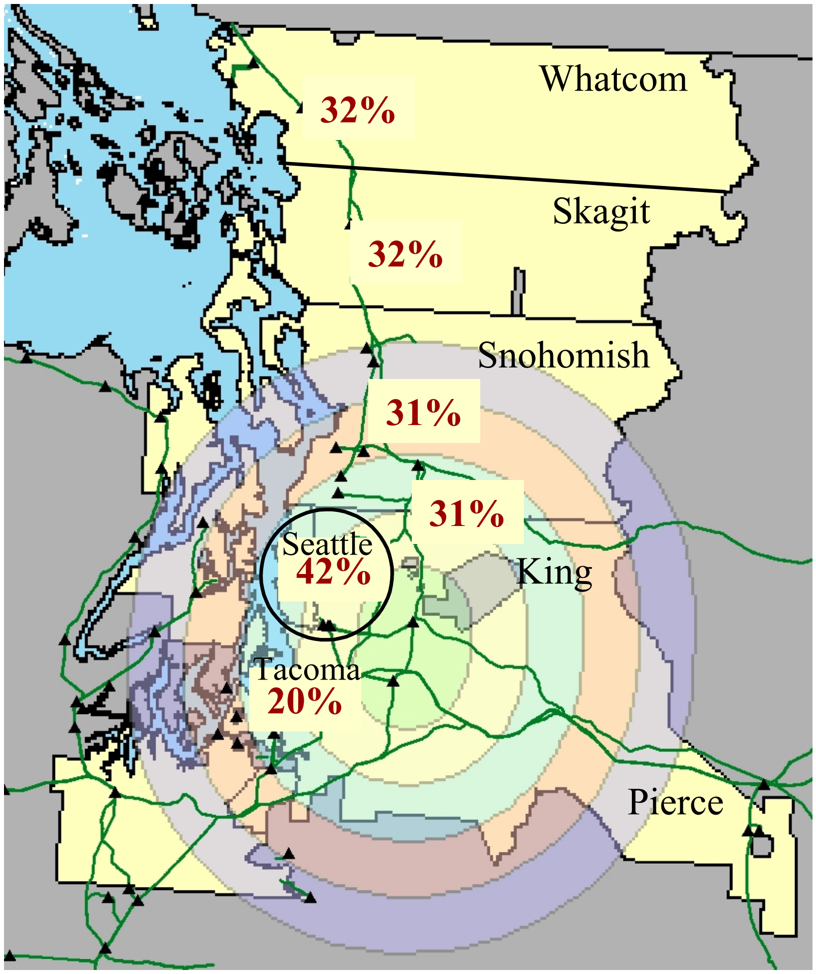
In 2004, a cold weather adjustment factor of 10.4%, instead of 17.3%, would result in a loading of 2850 MVA at the Covington substation. By 2007, the maximum weather adjustment is only 2.1%. While the cold weather adjustment does help drive the need for the line in the early years, in the long run the line is needed to serve peak loads even during an average winter.

4.4 Puget Sound Area Transmission Network

The load forecasts described in this section represent total load in the Puget Sound area, from Tacoma in the south to the Canadian border in the north. However, load reduction at different locations will have a different effect on Covington transformer loadings due to network power flow interactions. For example, the 230 kV Covington-Duwamish line connects the Covington substation directly with the heavy industrial area south of downtown Seattle. A 100 MW load change in this area changes loadings on the Covington transformers by 42 MW. Load changes in other areas have a lesser effect. This means that the effectiveness of any load reduction or distributed generation program will vary by location. Figure 13 shows the area and the load-flow distribution factors for load reduction in different parts of the Puget Sound Area.

The factors measure the effect of a change in *net* load on the Covington transformers. This means that they apply equally to both changes in generation and load. Adding generation in the Seattle load center by 100 MW would have the same effect on the transformer loading (reducing it by 42 MW) as reducing the load by 100 MW.

Figure 13: Map of the Study Area and Load-Flow Distribution Factors



Section 5. Alternatives to Transmission Expansion

A broad range of alternatives was included in the economic screen: Demand-Side Management (DSM); Distributed Generation (DG); large scale Generation (G); and Demand Response (DR). We give an overview of the measures and technologies in the following sub-sections, details about specific measures can be found in the Appendices.

5.1 Overview of the Types of Demand Response (DR) Programs

DR programs are a potential source of load reduction that could be exercised during an 'Arctic Express' event to prevent overloads on the Covington transformers. These options include Direct Load Control (DLC), interruptible / curtailable (non-firm) rates, and demand bidding (i.e. the Demand Exchange) to reduce loads when needed during system peaks. These types of solutions are an effective approach to achieve load reductions because they directly address the capacity nature of the problem.

DR programs can be categorized into two major types: 1) Price-based dispatch programs that offer customers incentives to voluntarily curtail load during the peak; and 2) Pre-arranged contracts with customers (such as interruptible / curtailable rates or direct load control) that would require a customer to reduce loads during the system peak for a fixed price at BPA's request. These programs differ in their implementation and potential for providing load relief as discussed below. In this analysis we evaluate both 'price-based dispatch' and 'interruptible/curtailable' for their capability to provide the needed capacity to BPA.

5.1.1 Price-Based Dispatch

Price-based dispatch programs are voluntary programs in which the price for curtailment or interruption is determined through a price convergence mechanism (i.e. auction, bidding system, etc.) between load serving entities and customers. Customers can choose the point at which the price available to them is high enough to offset their productivity losses from reducing or shutting-off their load. If the price offered by the load serving entity is high enough, then sufficient load reduction can in, all probability, be purchased at that price. While price-based dispatch programs result in a particularly efficient process of load reduction they do not provide firm or guaranteed reductions in system load when needed.

It is particularly important with regard to the KEL project to factor in the probability of achieving load reduction during 'Arctic Express' conditions. For example, during an extreme weather condition, it is unlikely that residential, commercial, and retail customers would curtail their heating load. Additionally, because there is no guarantee that the customer will reduce load, BPA-TBL cannot be certain that their demand reduction targets, required for reliability, will be met through a price-based dispatch program. More experience with these types of program in achieving peak load relief in a targeted area may reduce this uncertainty.

The curtailment period can be specified for any appropriate period of time, e.g. real-time, day-ahead when curtailment is required. These are flexible, market-based programs that allow for efficient load reduction during peak periods, emergencies, or when costs are highest for the load serving entities.

Price-based dispatch programs have low utility transaction costs once the initial program implementation is completed. A large number of customers can participate because the marginal cost of including additional customers is also low. Additionally, the higher the penetration throughout the customer base, the more likely the load serving entity would be able to operate an efficient market that matched customer participation with available incentive payments, thereby targeting the programs so as to achieve highest participation.

5.1.2 Interruptible / Curtailable and Demand Response Contracts

Interruptible / curtailable contracts differ from the price-based dispatch programs because the terms (i.e., number of times/year the customer can be curtailed, maximum hours per interruption, and notification period for interruption) and the price (fixed component) are pre-determined and bound with an enforceable contract. By securing a contract for the load reduction, the available peak load relief is more certain for planning purposes. This type of program is better suited for the type of system conditions driving the need for the KEL transmission line, where extreme but infrequent weather conditions result in high levels of load relief required over relatively few hours of the year.

As with the price-based dispatch programs, the curtailment period varies with the contract. Also, the notification time frame for curtailment or service interruption is variable. The price paid for interruption or curtailment is typically higher when there is less notification time prior to load reduction or interruption. The notification period and other contract terms can be tailored to the needs of both the load serving entity and the customer for reducing load. The transaction costs for these contracts are higher than the price-based dispatch contracts and thus these contracts are better applied to customers with larger loads.

For our analysis we consider contracts of existing generators to generate during the 'Arctic Express' as a form of demand response. These are contracts with owners of existing generators to call on them to dispatch during hours requiring peak load relief. Similar to other interruptible/curtailable contracts, the contract terms will specify the number of hours and frequency that the generator can be called on as well as the price.

5.2 Overview of Demand-Side Management Measures

DSM measures are typically considered energy efficiency measures rather than peak shaving programs. However, certain measures such as heating efficiency and weatherization will reduce heating loads and have an impact on peak demand reduction so we have included them in the economic screen. We used DSM cost and performance measures from the Northwest Power Planning Council (NWPPC) Database (http://www.nwppc.org/comments/default.asp). The analysis calculated the benefit/cost ratio of each measure with the inclusion of the specific avoided costs associated with the KEL line. Although the focus for the DSM screening was to find winter peak shaving programs, all DSM measures available from the NWPPC database were screened. In Table 11 we summarize the number of DSM measures by sector (residential, commercial, etc.) and end-use (heating, lighting, appliances, etc.). In total we screened 1533 measures from the NWPPC database.

Table 11: Summary of DSM Measures

End Use	Residential	Commercial	Industrial	Other	TOTAL
Heating	108 (plus 16 AC Measures)	2			126
Envelope	23	8			31
Lighting	21	652			673
Water Heating	16				16
Appliances	7	4			11
Exit Signs		7			7
Motors			657		657
Traffic Signals				10	10
Vending Machines				2	2
TOTAL	191	673	657	12	1,533

5.3 Overview of Generation and Distributed Generation

There are a variety of generation options that could help to defer the KEL transmission line, including both existing and new generation. In the course of this study we identified 277MW of additional capacity that could potentially be available from existing generators in the Puget Sound area.[15] An additional 270MWs of capacity are currently under construction. Together, these plants could provide up to 170MW of relief at the Covington substation. Another 2,700MW of capacity are either permitted or planned, although it is uncertain how much, if any, of this capacity will eventually be constructed.

In order to be successful in deferring the need for the project, a generator would have to be available to operate during the heavy load hours when an outage would cause an overload on the Covington transformer banks. The contractual disposition of the power supply is irrelevant; the generator need only be operating and feeding power into the grid in order to reduce the power flow across the transformer banks. However, BPA would need to be able to rely on the generator being able to provide the energy whenever required. Because the potential consequences for failing to deliver could be a widespread blackout in the Puget Sound area, BPA would need a fairly ironclad guarantee that the generator would be ready when called upon.

5.3.1 Existing Generation

BPA makes assumptions about the disposition of existing generators when it conducts its studies of the power flows across critical transmission system elements. BPA generally assumes that all generators in the Puget Sound area would be running in order to meet the extremely heavy loads during an Arctic Express event. However, this analysis uncovered approximately 390MW of

[15] Most of the generation capacity numbers in this section came from the Northwest Power Planning Council databases available at http://www.nwcouncil.org/energy/powersupply/Default.htm. These include the *Existing Generating Projects* and *Generating Project Development Activity* databases, which were last updated on 6/18/02.

capacity at several generating stations in the area that is not running for BPA's load flow studies. This capacity could potentially be called upon by BPA during the target hours.

Plants that are not running at full capacity for BPA's studies include Ross Dam, a hydroelectric project owned by Seattle City Light; Pierce Power, a gas-fired peaker owned by TransAlta, and a number of smaller gas turbines that were installed in 2001 during the height of the electricity crisis. A complete list of these facilities is presented below in Table 12.

Table 12: Existing and Potential Large Generators in the Puget Sound Area

Project	Location	Type	Available Capacity (Local MW)*	Effective MW at Covington
In service			*277*	*70*
Pierce Power	Frederickson	Gas turbine	154	31
Ross Dam**	Skagit River	Hydroelectric	109	46
BP Cherry Point GTs	Blaine	Gas turbine	73	23
Equilon GTs	Anacortes	Gas turbine	39	12
Georgia-Pacific GT	Bellingham	Gas turbine	11	4
Construction (Phase 1)			*268*	*56*
Frederickson Power 1	Frederickson	Combined-cycle	249	50
Tesoro (Permanent ICs)	Anacortes	Reciprocating engine	19	6
Permitted (Phase 2)			*1,156*	*365*
Sumas Energy 2	Sumas	Combined-cycle	660	211
Everett Delta I	Everett	Combined-cycle	248	77
Everett Delta II	Everett	Combined-cycle	248	77
Potential (Phase 3)			*1,643*	*460*
BP Cherry Point Cogen.	Blaine	Cogeneration	720	230
U.S. Electric Cherry Point	Blaine	Coal–Steam	349	112
Frederickson Power 2	Frederickson	Combined-cycle	280	56
Tahoma Energy Center	Frederickson	Combined-cycle	270	54
Cedar Hills	Cedar Hills Landfill	Landfill Gas	24	7
Maximum Available Puget Sound Area Generation			***3,344***	***950***

* Includes only capacity that is not already assumed to be operating in BPA's load flow studies.
** Ross Dam is unlikely to be available during a multi-day Arctic Express event.

There is no certainty that these plants are actually available to be dispatched during the target hours. Ross Dam has environmental or water availability constraints that prevent a sustained dispatch above the level assumed by BPA. The smaller gas turbines that were installed during the electricity crisis may have been retired in the months since wholesale electricity prices receded to historic levels. Still, these facilities represent a potential resource that could be investigated for their ability to serve as a transmission alternative.

If the generators are available, BPA could contract with the facility owners to provide capacity during the target hours. This option might be relatively inexpensive, as the generators would already have a strong incentive to operate because wholesale energy prices are likely to be high during an Arctic Express event.

5.3.2 New Large-Scale Generation

In addition to the existing facilities, a number of new, large power plants have been proposed for the Puget Sound area since the late 1990s. Nearly all of these plants would be large natural gas-fired, combined-cycle combustion turbine plants. Together, these plants would add approximately 3,000MW of generating capacity. Of course, many if not most of these projects will never be built. Still, even one of the larger projects could significantly reduce the need for the KEL Transmission Project.

Two projects are already under construction in the Puget Sound area: Frederickson Power 1, a 249MW combined cycle combustion turbine facility in Pierce County, and 19MW of natural gas-fired reciprocating engines under construction at the Tesoro refinery in Anacortes. If both of these plants come on line, they could provide approximately 50MW of loading relief at Covington. If these projects are on line before the winter of 2004, BPA might be able to obtain a commitment to operate during the target hours for a minimal cost.

Plants that already have all of the necessary permits but have not yet begun construction include the 660MW Sumas Energy 2 project in Whatcom County and the two 248MW Everett Delta projects. These projects could provide 450MW of relief at Covington. Projects that are either in the permitting process or are planned could provide an additional 1,000MW of relief.

The disposition of these plants is much more speculative. The analysis undertaken for this high-level screening project indicates that new power plants not already in the construction stage are not economic at this time. However, this conclusion is heavily influenced by the assumptions and methodologies used to forecast electricity and natural gas prices. The forecasts indicate that, for the next few years, the revenue available from the wholesale electricity market is insufficient to recover both the fixed and variable costs of a natural gas-fired, combined-cycle combustion turbine power plant. By 2006, electricity prices are forecast to rise to a level that would support the development of new power plants.

Because new plants are uneconomic on their own, they would probably need incentive payments from BPA in order to be available before the latter half of the decade. As a consequence, this option is likely to be more expensive than contracting with existing facilities to provide capacity during the next few years. Under the assumptions used for this analysis, the incentive needed for the 2003-2005 period would be approximately $25 per kW, or $12.5 million for a 500MW plant.

5.3.3 Regional Availability of Natural Gas

One issue that arose during the course of this study is the availability of natural gas, and the ability of the region's natural gas system to deliver the gas to all of the existing and new natural gas-fired generators in the Puget Sound area. As generating capacity would be needed by BPA during the highest loads of an Arctic Express event, this time period would almost certainly experience extremely high coincident demand for natural gas. Like electricity transmission, the natural gas delivery system has a fixed peak delivery capacity; once the limits of the system are reached, there is very little that can be done on short notice to increase deliveries. BPA relies on gas-fired generators to operate in order to avoid a Puget Sound-area blackout during an Arctic Express event. Therefore, the relevant question is: How can BPA be sure that the generators will be able to obtain fuel supplies?

A comprehensive answer to this question would require analysis of: the physical delivery capability of the interstate pipeline system, including the likely direction of flows on the bi-directional Northwest Pipeline (which is highly sensitive to price differences between the Canadian and Rocky Mountain producing regions); the take away delivery capability of distribution systems operated by local natural gas utilities, for a number of potential distributed generation sites; existing claims on such capacity, including the extent to which industrial sector demand is interruptible; and the availability of capacity at underground storage facilities, among other things. This analysis would need to be dynamic, incorporating likely and possible changes to the existing infrastructure, such as the Northwest Pipeline's Evergreen Expansion project, expected to be complete by November 2003. Such an analysis is beyond the scope of this report.

Nevertheless, the natural gas system has in place mechanisms for managing gas use during times of peak demand. For example, many large industrial customers, including some electric generators, have the ability to switch to diesel fuel. These customers typically take interruptible service, freeing up delivery capacity for firm customers during system peaks. For dual-fuel generators, natural gas supplies should not be an issue as long as the generators have the ability to obtain sufficient supplies of distillate oil in the event that gas service is curtailed. For single fuel generators, BPA might be able to obtain the certainty it needs by requiring generators to demonstrate that they have access to firm supplies of natural gas. If there were any question that the existing mechanisms would be unable to sufficiently ration access to natural gas, such that curtailment of firm customers became necessary, BPA might be able to work with the pipeline operators and local distribution companies to avoid curtailing the generators due to the importance of that generating capacity to the stability of the electricity grid.

While such an approach might not give BPA 100% certainty, less that 100% certainty is the reality for all elements that feed into the projected need for the KEL project, including the accuracy of utility load growth forecasts, the appropriateness of the weather adjustments, assumptions about utility-owned generation being online, etc. Whether generators would be able to obtain firm gas supplies with the incentive level BPA can offer might not be known until the implementation phase.

5.3.4 Existing Distributed Generation

In addition to the existing large generation discussed above, there are also small-scale distributed generators in the Puget Sound region. According to BPA's estimates, existing idle DG at local industrial sites, banks, hospitals etc., amounts to approximately 60MW in the region. This translates to less than 20MW available at Covington after applying the appropriate load flow factors. This idle capacity could potentially be called upon by BPA during the target hours. However, because of the low levels of available capacity from these generators, we excluded them from further analysis in this high-level economic screen.

5.3.5 New Distributed Generation

Small-scale, distributed generation can often serve as a substitute for investment in transmission or distribution circuit. However, in this case, the potential overload is sufficiently large and the load area sufficiently diverse such that distributed generation does not appear to be a viable alternative given the available dollars from deferring the KEL.

The distributed generation technologies that were considered in this analysis are listed in Table 13, below. The extremely low capacity factors at which these units are projected to operate make them uneconomic if considered solely as a transmission alternative. However, some of the technologies, particularly behind-the-meter technologies such as diesel generators, reciprocating engines, or small gas turbines, might provide additional benefits such as backup power to their owners, defraying some of the costs of the units. In addition, the project owners might be able to sell the energy to their local utilities or into the wholesale power market. However, it is unlikely that sufficient capacity could be built with the relative low incentive that BPA can offer.

Table 13: Generation Technologies Considered for High-Level Screening

	Combined Cycle Combustion Turbine	Simple Cycle Combustion Turbine	Cummins ORU Genset	Generic Diesel Engine	Gas Spark Ignition	Low Temp (PEM) Fuel Cell	High Temp Fuel Cell
Operating Data							
Heat rate	7,618	11,380	8,000	10,000	9,000	9,000	7,000
Lifetime (yrs)	25	25	25	25	25	25	25
Fuel	Gas	Gas	Diesel	Diesel	Gas	Gas	Gas
Avg. Fuel Cost	$3.90	$3.90	$6.09	$6.09	$3.90	$3.90	$3.90
Capacity Factor	90%	10%	10%	10%	10%	90%	90%
Smallest (kW)	50,000	500	1,000	500	300	1	1
Largest (kW)	750,000	50,000	5,000	10,000	5,000	250	250
Plant Costs							
Initial Cost ($/kW)	$523.06	$369.90	$558.32	$550.00	$550.00	$3,000.00	$4,000.00
Total Fixed Annual	$23.23	$11.14	$16.69	$16.61	$16.61	$16.61	$16.61
Fixed O&M ($/kW-yr.)	$18.00	$7.44	$11.11	$11.11	$11.11	$11.11	$11.11
Property Tax ($/kW-yr.)	$5.23	$3.70	$5.58	$5.50	$5.50	$30.00	$40.00
Variable O&M ($/MWh)	$0.60	$0.12	$3.50	$20.00	$15.00	$15.00	$10.00

5.3.6 Renewable Generation and Emerging Technologies

Renewable generation such as wind and solar were not considered for this study, because their resource characteristics are a poor match for BPA's needs to defer the KEL project. Wind energy was excluded because the Puget Sound Area is not home to a commercial-grade wind resource. Solar was excluded because the critical hours occur during the winter months when solar radiation is scarce, and many of the target hours occur during the evening. Fuel cells do not suffer from these disadvantages, and were considered for the high-level screen. However, their extremely high cost makes them unattractive as a substitute for the KEL project.

Section 6. Base Case Economic Screening Analysis

In the first stage of the economic screen we use base-case input assumptions for the cost-effectiveness tests of non-wires options. In this base case analysis we include assumptions about:

1. Fuel price forecasts
2. Operations and maintenance costs
3. Inflation, discount, and financing rates
4. Utility rates and average customer costs by customer
5. Environmental externality costs
6. Load reduction requirements
7. KEL revenue requirement (all-in-cost of the KEL transmission line)
8. Transmission avoided costs
9. Avoided line loss savings
10. Electricity market prices

Items one through five are considered fixed input assumptions, but later in Section 7 we look at alternative scenarios for items six through ten to test the sensitivity of the cost-effectiveness results to these highly variable inputs.

6.1 Fixed Input Assumptions

6.1.1 Natural Gas and Distillate Oil Price Forecasts

Natural gas and distillate oil prices are inputs to the running costs of DG and other generation resources. These prices are also used in our forecasts of electricity market prices. For the purposes of our analysis we used fuel forecasts from the Northwest Power Planning Council. The Council published draft natural gas and distillate oil price forecasts for its 5th Power Plan in April of 2002.[16] The Council forecasts U.S. wellhead prices through 2025, and then adjusts these prices to reflect the costs of delivering power to end-users. This study uses the Council's forecast of delivered natural gas prices for Westside electricity generators and utility distillate oil prices, adjusted for inflation to 2002 dollars. Fuel price forecasts are shown graphically in Figure 14 and Figure 15 below.

[16] Northwest Power Planning Council, *Draft Fuel Price Forecasts for the 5th Northwest Conservation and Electric Power Plan*, April 25, 2002, p. F-1.

Figure 14: Natural Gas Price Forecast

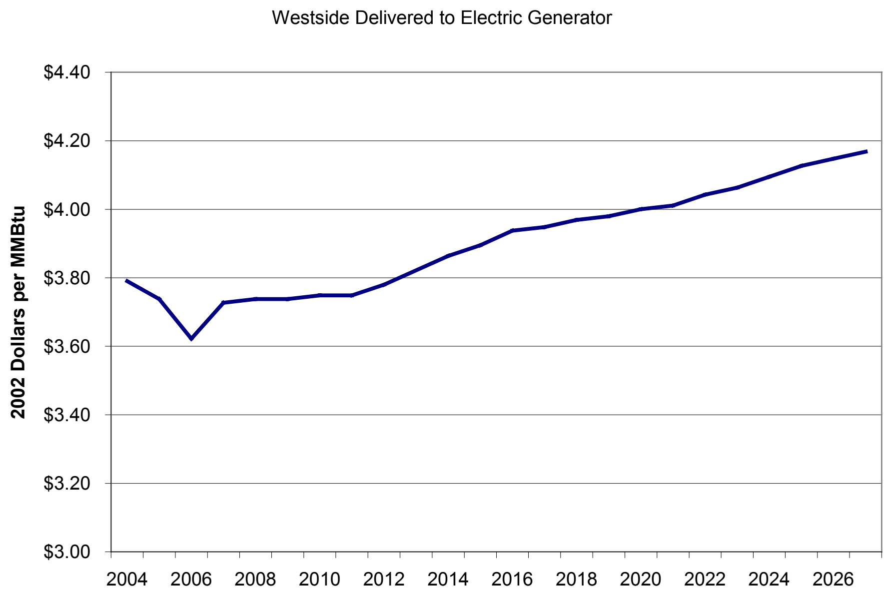
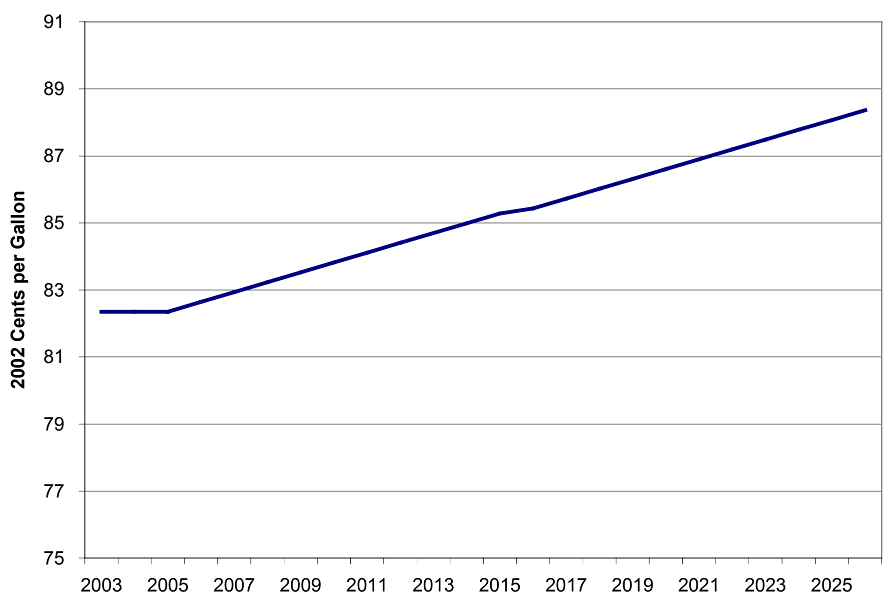


Figure 15: Distillate Oil Price Forecasts



6.1.2 Operations and Maintenance (O&M) Cost Assumptions

For the purposes of this analysis, we applied an O&M cost value of $50,000 per year. This is the annual O&M cost associated with the maintenance of the KEL line if it were built. TBL provided this value based upon expenses for similar projects. While these types of costs can vary significantly for different projects, this value is a comparatively small portion of the overall costs of the construction of the KEL transmission line. Therefore, even though it is important to include this cost in the overall analysis, it is kept constant throughout and the entire amount is added to the maximum annual incentive payment calculated during the avoided cost analysis.

6.1.3 Inflation and Discount Rate

The inflation, discount, and financing rates applied throughout the economic screening analysis were provided by BPA and are shown in Table 14.

Table 14: Discount and Inflation Rate Assumptions

Financial Input	Value
Real Utility Discount Rate (9% nominal, 2.7% inflation)	6.1%
Real Societal Discount Rate	3.0%
Financing Rate for Generators/DG	12.5%

6.1.4 Utility Rates and Average Customer Costs by Customer Type

For the purposes of the economic screening analysis, we used average rates for the three major customer classes: residential, commercial, and industrial. While average rates do not exactly match the rates in each distribution utility's territory, they do provide a reasonable approximation for a screening study. A more detailed program design (for implementing a cost-effective program) would use the utility-specific rates. Table 15 outlines the average $/ kWh rates for the four local distribution utilities included in the analysis. The rates used in the screening analysis (column two) are intended to be representative of current posted rate schedules and are not intended to accurately reflect billing rates for particular customers.

Table 15: Average per kWh rates for Local Distribution Utilities

	Average Used in Screen	Tacoma Power	Seattle City Light	Snohomish	Puget Sound Energy
Residential	$0.065/kWh	$0.06	$0.06	$0.08	$0.07
Commercial	$0.055/kWh	$0.03	$0.05	$0.07	$0.06
Industrial (Contract)	$0.050/kWh	$0.02	$0.05	$0.05	$0.04
Distribution Utility Distribution Rate	$0.030/kWh				
Transmission Average Rate	$2.56/kW-month				

6.1.5 Environmental Effects

Throughout the economic analysis, only tangible financial impacts that are applicable to each measure are included in the benefit-cost model. An estimation of tangible financial impacts for environmental externality effects is not readily available for this region. However, many of the alternatives we analyzed have positive environmental effects for each measure within the Societal Cost Test perspective. Consequently, to reflect the environmental benefits of the measures tested, we used the Regional Technical Forum's (RTF) recommended environmental monetary estimate of $15/ton of carbon dioxide emissions.[17] This estimate stems from the conclusion by the RTF that there exists "a risk that serious damage will result from continued increases in greenhouse gas concentrations in the atmosphere." Thus, the monetary value of $15/ton of carbon dioxide represents the reduction in this risk.

The environmental externality value is only used during the calculation of the Societal Cost Test and is not applied to any other Cost Test perspectives in the economic analysis.

6.2 Base Case Assumptions for Variable Inputs

6.2.1 Load Reduction Requirement

The base case for the required load reduction is taken from the forecast compiled by TBL and the project team's load duration curve estimation as described in Section 4. Our analysis indicates a deficiency of 122MW during the winter of 2003 / 2004. In Table 16 we show the maximum overload and number of overload hours per year for the years 2004 through 2013.

Table 16: Projected Covington Transformer Bank Overloads, 2004-2013

Year	Maximum Overload (MW)	Number of Hours Overload Occurs
2004	122	10
2005	190	17
2006	269	30
2007	397	51
2008	449	61
2009	505	70
2010	558	86
2011	611	102
2012	664	119
2013	714	135

[17] "The Regional Technical Forum's Recommendations to the Bonneville Power Administration Regarding Conservation and Renewable Resources Eligible for the Conservation and Renewable Resources Rate Discount and Related Matters" Regional Technical Forum, September 1, 2000, pp. 27-28.

6.2.2 KEL Revenue Requirement (Cost of Line)

We assume a base case revenue requirement of $25 million for the line including construction, mitigation and other costs, plus O&M costs of $50,000/year.

6.2.3 Transmission Avoided Costs

In Table 17 we show the base case transmission avoided costs as calculated in the methodology section. These avoided costs include the increased O&M costs once the new line is built. For example, if the KEL line is deferred for 3 years, the transmission avoided costs would be $5.70 per kW of load reduction at Covington substation. Transmission avoided costs are used to set the maximum incentive levels in the economic analysis.

Table 17: Net Transmission Avoided Costs

Years of Deferral	3	5	10
Net T Avoided Cost ($/kW-year)	$ 5.70	$ 3.50	$ 2.33

6.2.4 Avoided Line Loss Savings

Table 18 provides the avoided line loss savings if the KEL line is deferred for 3, 5, and 10 years. If the KEL line is deferred, the line loss savings that could be achieved if the new line is built would also be delayed. For example, if the line is deferred for 3 years, each kW of load reduction costs $7.34/kW-year in avoided savings.

Table 18: Base Case Avoided Loss Factors

Years of Deferral	3 Years	5 Years	10 Years
Avoided Loss Factor ($/kW-year)	$ 7.34	$ 4.51	$ 2.99

6.2.5 Electricity Price Forecasts

The team developed a methodology to forecast future electricity market prices using data from Platts' *Electricity Daily*, assumptions about the long-run marginal cost of a new combined-cycle, combustion turbine power plant, and the Northwest Power Planning Council's draft natural gas price forecasts.

Electricity Daily reports prices for "Forward Assessments" for each calendar year through 2005 for various locations, including Mid-Columbia. These quotes reflect the expected price of a flat block of power delivered daily to Mid-Columbia over the course of a year. As of September 16, 2002, the Mid-Columbia Forward Assessments were $38 for calendar year 2003, $39 for 2004, and $40 for 2005. These prices are for delivery to Mid-Columbia. Ideally, an adjustment would be applied to reflect the different, presumably higher, value of energy on the west side of the Cascades due to transmission system congestion. However, in the absence of meaningful congestion price data, no such adjustment is possible.

For 2006 and beyond, the market price of electricity is assumed to be equal to the fully allocated cost of a natural gas-fired, combined-cycle, combustion turbine power plant. This cost is based on the generation cost data developed by E3 for this study. The fully allocated capital cost of such a plant is calculated to be $10.90 per MWh. This cost stays constant throughout the forecast period. The plant operating cost varies from $29 in the early years to $32 per MWh toward the end of the forecast, based on rising natural gas prices in the NWPC forecast. Using this approach, the team developed a base case market price forecast for electricity averaging $40.03 per MWh through 2027.

The base case forecast is consistent with a scenario in which reduced load due to the 2000-2001 western energy crisis leads to a surplus of electricity on the wholesale market in the short-term. As loads recover, the surplus shrinks and prices begin to rise until they reach the level at which it becomes economic to build new power plants. By 2006, when loads have recovered fully, the region is in resource balance and prices reach equilibrium at the cost of a natural gas-fired power plant. This methodology assumes that long-term prices above this level will lead to the construction of new plants, driving prices down, while prices below this level would lead to the retirement of existing plants that are uneconomic, driving prices up. Of course, actual market prices could be either higher or lower than this benchmark in any given year, and are likely to be quite volatile. These situations are addressed in the sensitivity analysis described in Section 7.

6.3 Results from Technologies/Measures Analyzed

With the base case assumptions, we find that there are no alternative measures that are cost-effective from both the TBL RIM perspective and the Participant Cost test. If the Participant Cost Test has a B/C ratio less than one, the participant is worse off from participation in the program versus non-participation. It is difficult to get significant participation for these types of programs. This means that there are no programs that make BPA rates lower relative to construction of the KEL line and leave the participant (either the generation owner, the recipient of the DSM, or participant in a DR program) better off (a win-win situation).

The team also calculated results using cost tests focused on the other stakeholders. These perspectives are important to evaluate as well since they indicate the relative impact on other interested parties such as the distribution utilities, and a broader societal perspective of the alternative relative to the KEL line.

In Table 19 we show the benefit cost ratios for one of each of the DSM, DG, DR, and G alternatives. The alternatives shown were chosen as the measure or technology with the highest B/C ratio from the RIM-BPA/TBL perspective. The relationship of the B/C ratios for the other measures and technologies are similar for each type. Detailed calculation of B/C ratios is included in the appendices.

The DSM measures evaluated are not cost-effective from the BPA TBL/RIM, or Utility Cost Test, but are cost-effective from the Total Resource Cost Test, Societal Cost test, and Participant Cost Test. The poor performance with RIM is typical for efficiency measures. Since the only impact of the measure on TBL rates is the capacity load relief, the costs of efficiency measures are relatively high compared to the benefits. In addition, lost sales are a cost from the RIM perspective and in the case of the KEL line, the transmission rate of $2.56/kW-mo or $10.24/kW-year (assuming 4 heating months) is much higher than the transmission avoided costs of $1.70/kW-year ($5.30 times a load distribution factor of 32%).

We analyzed the distributed generation technologies using an incentive payment equal to the full value of avoided transmission costs. Therefore, from the utility cost test perspective the benefits and costs are equal and there is a BC ratio of 1.0. The additional cost of revenue loss that a behind-the-meter generator will cause makes DG not cost-effective from the TBL BPA RIM perspective. DG is not cost-effective from the TRC or Societal perspectives due to the relatively higher cost of generating energy with small-scale generation and the energy savings associated with building the KEL line.

For generation (G) technologies, the incentive level was set equal to the transmission avoided cost, resulting in a RIM and Utility Cost Test BC ratio of 1.00. Since there is no revenue loss associated with large-scale generation connected to the BPA transmission system, these cost tests result in the same answer. The participant cost test for the generation owner is very close to 1.0 indicating that a new central station plant would be nearly cost-effective with the base case assumptions. This finding for the merchant plant is very sensitive to the assumptions made in the market price forecast.

The team estimated the BC ratios for a conceptual BPA demand response program with an incentive payment equal to the transmission-avoided costs. At this incentive level, the RIM and Utility Cost Test BC ratio is 1.0. The measure is not cost-effective to the participant because the incentive level is less than the value assumed for the foregone load (Assumed to be $150/MWh) in the base case. The results are very sensitive to this assumption and are described in more detail in Section 7, which describes the sensitivity analysis. Demand response programs are not cost-effective from the TRC and Societal perspectives because the energy savings associated with building the line are greater than the financial benefits of deferring the line.

Table 19: Benefit Cost Ratio of Alternative with the Highest BPA TBL RIM BC Ratio

	DSM	DG	DR	G
Alternative	Single Family Heating	Gas Spark Ignition	BPA (Conceptual)	Combined Cycle Combustion Turbine
RIM-BPA/TBL	0.0004	0.01	1.00	1.00
Utility Cost	0.02	1.00	1.00	1.00
TRC Cost	1.94	0.56	0.56	1.56
Societal Cost	2.40	0.50	0.60	1.10
Participant Cost	2.20	0.56	0.78	0.99
RIM-LDC	0.71	1.03	0.80	Not Effected

(1) Program NWPC Description: Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP w/PTCS - Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS

In Table 20 we show the number of the 1,533 DSM measures that were cost-effective from each of the cost-test perspectives under the base case assumptions. None of the measures were cost-effective from the TBL RIM or Utility Cost Test; however, most were cost-effective from the TRC, Societal, and Participant cost tests.

Table 20: Number of Cost Effective DSM Measures from Each Perspective

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC	Total # of Measures
DSM	0	0	1034	1179	1523	1	1533

6.4 Summary of DSM Demand and Energy Savings

As part of the economic screening for cost-effective non-wires alternatives to the KEL transmission project, the team explored the penetration potential of cost-effective alternatives as discussed in Section 8. We did not investigate the penetration potential of DSM programs because these measures failed to pass the RIM test from TBL's perspective. However, over two thirds of the 1533 DSM measures examined did pass the TRC test perspective (See Table 20). While a DSM penetration potential analysis is beyond the scope of this project, from our DSM results we estimated the size of the energy efficiency program that would be necessary to achieve the demand reduction that is required to defer the KEL line.

Of the 1,533 DSM measures examined 1,034 passed the TRC cost test under our base case assumptions. From these 1,034 measures, the average coincident system-peak demand saving per program is 0.33 kW, and the average annual kWh saving is 3,933 kWh. So for each kW saving during the system peak period we would expect 11,950 kWh of annual energy savings.[18] If the 381 MW[19] reduction required to defer the KEL line for one year was to be achieved through an average mix of cost-effective DSM programs,[20] we would expect to see a corresponding annual energy reduction of roughly 4,556,000 MWh.

Lastly, if we were to focus the DSM efforts on the ten measures with the lowest kWh/kW ratios (i.e., the measures that provide the highest system peak demand reduction for the least amount of energy sales reduction),[21] for each kW saving we would expect 3,376 kWh of energy savings. With those focused programs, we would see only about 1,287,000 MWh of energy reduction in attaining the 381 MW of required load reduction.

If instead, we were to focus on the ten most cost effective programs (from the TRC perspective) in terms of either $/kWh net benefit or $/kW net benefit, the associated energy savings would be about 4,800,000 MWh per year. This range of 1,287,000 MWh to 4,800,000 MWh of energy reduction provides an indication of the magnitude of the DSM effort that would be required to meet the line deferral requirements. This is summarized in Table 21 below.

Table 21: DSM Program Energy Savings

	System KW Savings	Annual kWh Savings	kWh/kW	Load Reduction Requirement for Year 1 (MW)	Expected Annual MWh Savings
All Programs	0.3291	3,933	11,950	122 MW at Covington or 381 MW within the Puget Sound Area	4,556,115
Top 10 for lowest kWh/kW ratio (1)	1.9771	6,674	3,376		1,287,005
Top 10 for $/kW (2)	4.8442	60,016	12,389		4,723,424
Top 10 for $/kWh (3)	4.8228	61,335	12,718		4,848,650

(1) Residential and small commercial heating programs
(2) Industrial efficient motors plus one residential heating measure

[18] This comparison is made based on system peak savings to reflect the impact at the Covington substation. The coincident system peak savings will be lower than the customer's peak load savings.
[19] Under the base case assumptions 122 MW of load reduction is required at Covington, which translates to 381 MW within the Puget Sound Area, assuming an average distribution factor of 32%
[20] Cost effective from TRC perspective
[21] These tend to be small commercial and residential heating programs.

(3) Industrial efficient motors

The range of 412,000 MWh to 1,500,000 MWh of required energy reduction is high compared to the level of annual growth in the Puget Sound Area of approximately 1,000,000 MWh.[22] The DSM programs would need to reduce energy each year from half to one and a half times the annual energy growth. Also, DSM efforts would either have to be funded externally to BPA or the additional costs passed through to TBL's ratepayers, because they do not pass TBL's RIM test.

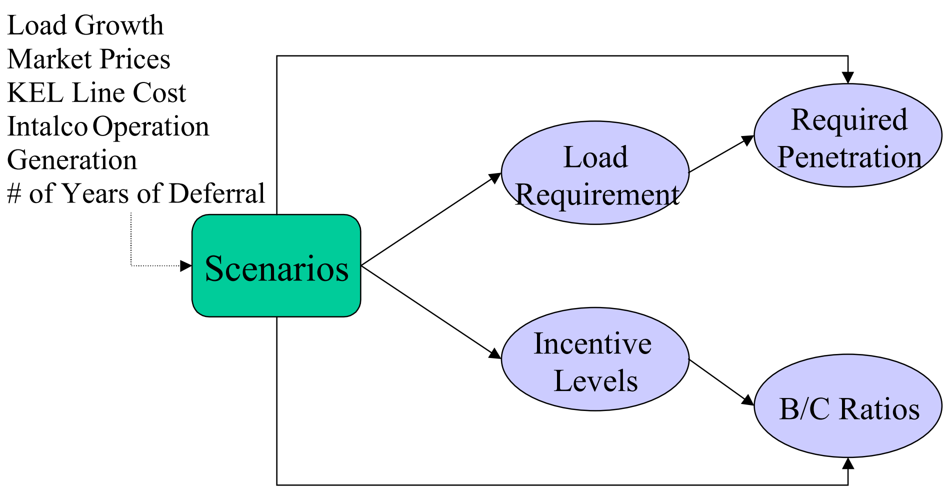
[22] Based on the average annual growth forecasted for the Puget Sound Area for 'normal weather' over the next 10 years of 173 MW and a 65% regional load factor.

Section 7. Sensitivity Analysis

The team evaluated a number of scenarios in which key economic inputs were systematically tested to determine if changes from the base case assumptions would change the conclusions. This section describes the development of alternative scenarios and describes the cost-effectiveness of transmission alternatives with assumptions more 'optimistic' and 'pessimistic' to alternatives than the base case we describe in Section 6.

In Figure 16 below, we summarize how we developed the scenarios. From the base case scenarios, we constructed high and low case scenarios for load growth, market prices, KEL line cost, and in-area generation operation. We then recalculated the load requirement and incentive levels using the same approach described in Section 3 and Section 4. In order to reduce the number of variations, we calculated B/C Ratios and penetration levels only for the more extreme 'optimistic' and 'pessimistic' combinations of inputs since this fully illustrates the range of results from the scenario analysis.

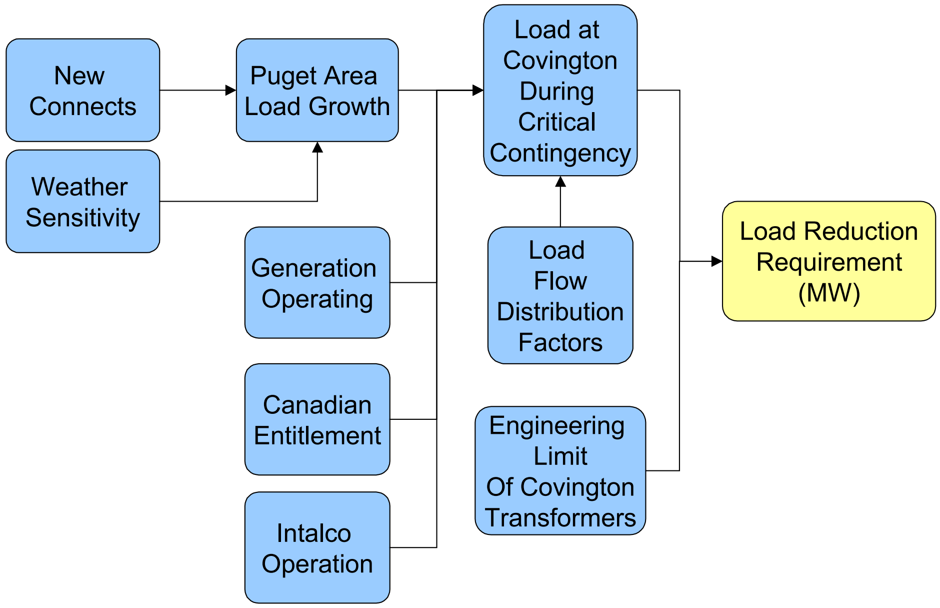
Figure 16: Scenario Analysis



7.1 Load Requirements

In Section 4, the numerous variables that contribute to the determination of load requirements are discussed in detail. Figure 17 is a flow diagram illustrating the analysis we used to calculate the load reduction required at the Covington substation. The base case variables used in the initial economic screening analysis are those variables that TBL currently uses in their planning. However, for the purposes of the load requirement sensitivity analysis, the input variables we modified are load growth and local generation operating during the critical 'Arctic Express' conditions.

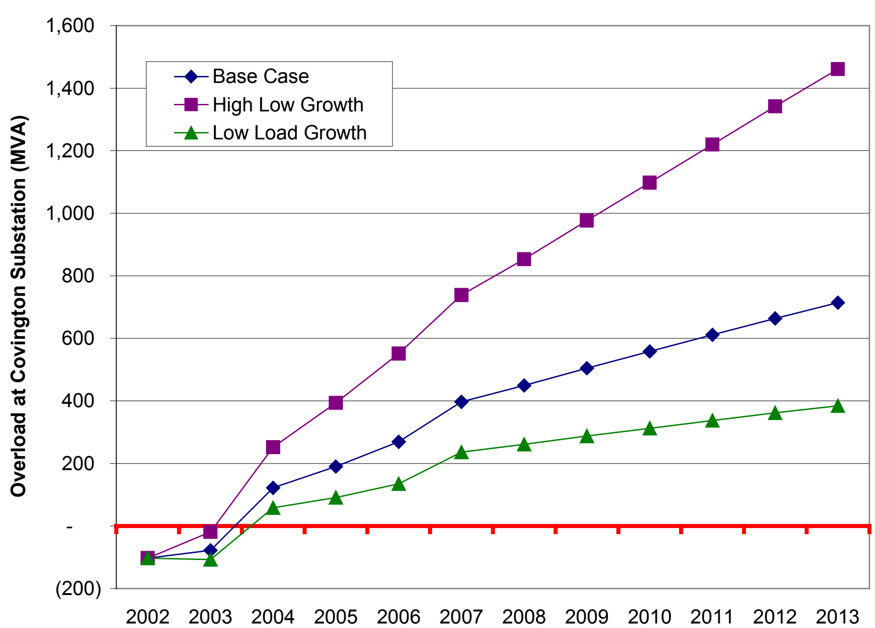
Figure 17: Simplified Flow Diagram of Load Reduction Requirement Calculation



7.1.1 Load Reduction Requirement Scenarios

The high load growth case was constructed by assuming that, beginning with the winter of 2002-2003, utility loads grow at twice the rate reported by local utilities (i.e., approximately 3%, vs. 1.5% in the base case); the low load case assumed a growth rate of half that reported by utilities (or 0.8%). The results of these sensitivity cases are presented in Figure 18, below.

Figure 18: Load Growth Sensitivity Cases



In addition to load growth, we used the amount of local generation operating as an additional sensitivity to the required load reduction. In the base case we assume that most, but not all generators are running at full capacity. This results in approximately 2,000MW of local generation. BPA also provided the team with high and low generation cases. In the high case, local generation was approximately 2,200MW. This case would reduce the overload at the Covington transformer banks by 53MW relative to the base case. In the low case, BPA assumed only 1,700MW of local generation. This case would increase the Covington overload by 93MW.

Table 22 summarizes the load growth and generation scenarios we used to develop load reduction requirement scenarios.

Table 22: Load and Generation Scenario Inputs

	Load Growth	Generation Operating
Base	1.5% growth	2,000 MW
Low	0.8% growth	1,700 MW
High	3% growth	2,200 MW

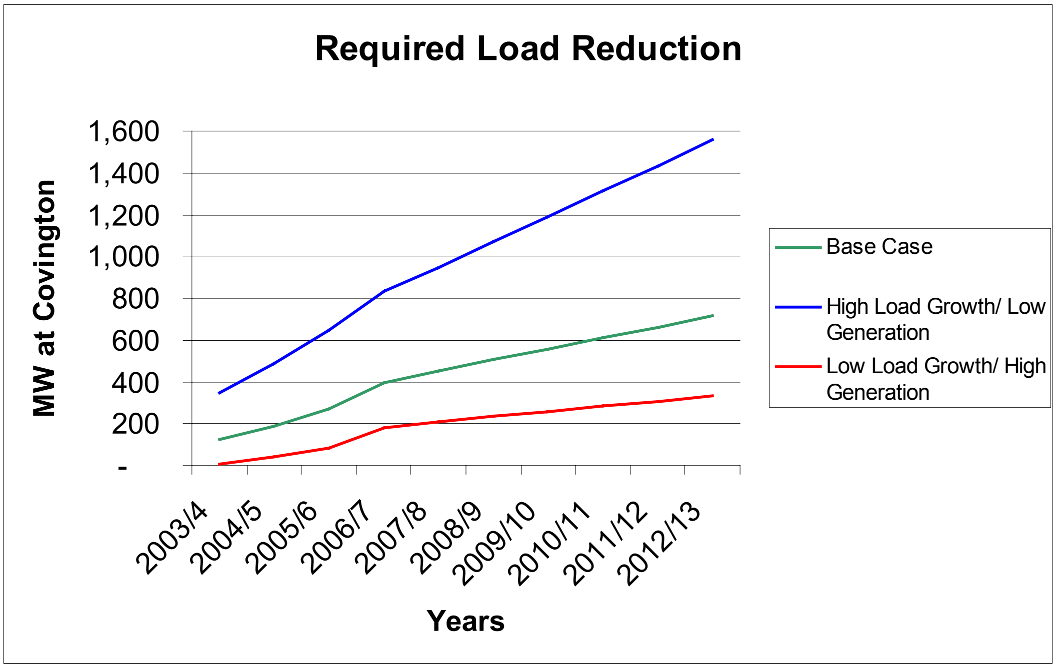
7.1.2 Scenario Results of Required Load Reduction

Applying the scenarios described in the previous section, we developed two scenarios around the base case to illustrate the effects of load growth and operating generation on the required load reduction. Table 23 summarizes the three scenarios shown in Figure 19 (base case plus two variations).

Table 23: Required Load Reduction at Covington (MW)

Scenario	2003/4	2004/5	2005/6	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13
Base Case	122	190	269	397	449	505	558	611	664	714
High Load Growth/ Low Generation	346	488	645	832	947	1,071	1,192	1,313	1,436	1,555
Low Load Growth/ High Generation	5	39	82	184	209	235	260	284	309	332

Figure 19: Required Load Reduction at Covington



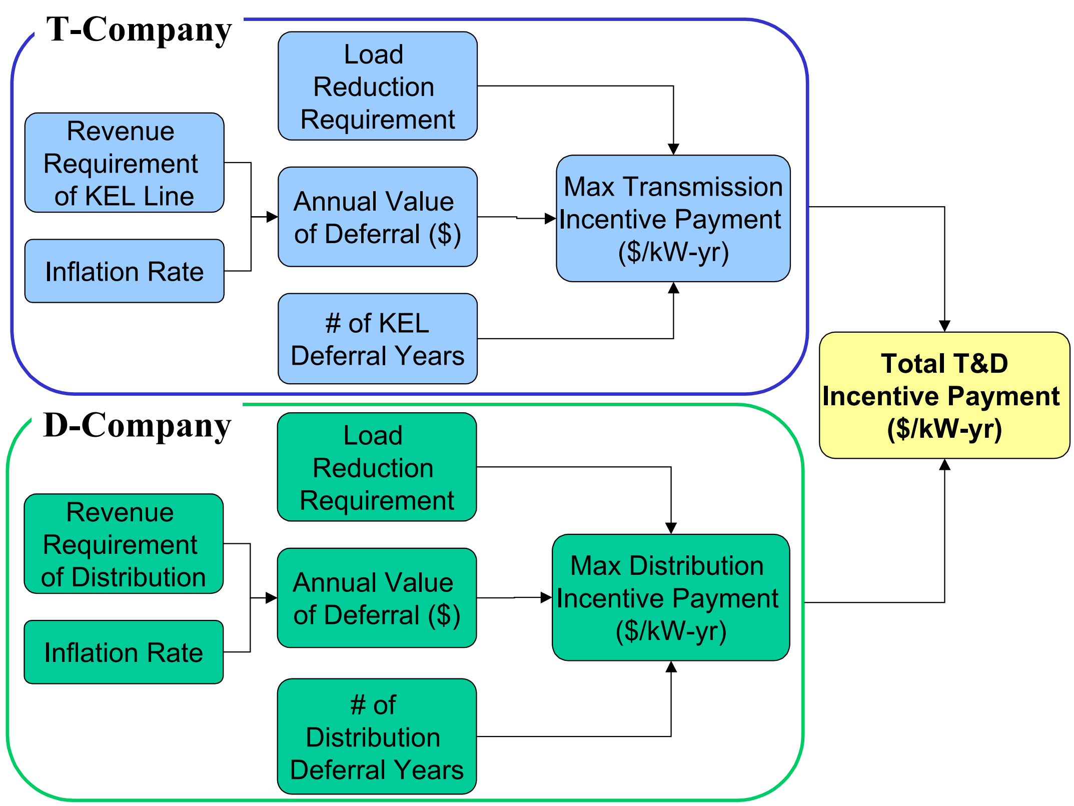
Even the low load case with high levels of generation operating would not, by itself, defer the need for the Kangley-Echo Lake project. We used this case as the 'optimistic' combination of factors for the required load reduction. The requirement begins at 5MW in the winter of 2003-2004 and increases to 82MW by the third year. Conversely, we used the case with high load growth and low generation to estimate the 'pessimistic' combination. In this scenario 346MW of load reduction at Covington is required in the first year and 551MW is required by the third year.

7.2 Incentive Payments

As described previously in Section 3.2, the revenue requirement of the KEL transmission line and the capacity required to defer it are the primary determinants in our estimation of the maximum incentive payments for TBL. However, other stakeholders may see deferred costs from the load reduction that is required to defer the KEL line. We describe in Section 3 the other benefits that are accrued in the TRC and distribution utility cost-effectiveness tests. These include avoided distribution capacity costs, avoided generation capacity costs, and avoided energy costs. If all stakeholders contribute to the program incentive payments up to the level of the net benefits they receive from the resulting load reduction, then this can result in increased incentive levels and higher program penetration. Our analysis sets the distribution system avoided cost to zero. Distribution avoided costs are area specific and experiences with utilities throughout North America have shown that the majority of distribution areas have excess distribution capacity and thus zero avoided capacity costs. Should a distribution company identify an area within the Puget Sound region with avoided distribution capacity costs then this would present an opportunity for a combined TBL/Distribution Company program whereby both companies would contribute to the program incentive payments.

We summarize pictorially the calculation of total incentive payments from the Transmission Company (TBL) and the Distribution Company in Figure 20. The maximum incentive payment on a $/kW-year basis is calculated by determining the total avoided cost per year and then dividing by the required load reduction over the number of years for project deferral. In this section, we develop scenarios of both the KEL revenue requirement and the required load reduction levels, and then calculate ranges of potential incentive levels.

Figure 20: Maximum T&D Incentive Payment Calculation



7.2.1 Maximum Incentive Payment Scenarios

7.2.1.1 Revenue Requirement Scenarios

TBL provided estimates of the revenue requirement under several construction scenarios, which are shown in Table 45. We assume a base case revenue requirement of $25 million for construction, mitigation and other costs. The low cost scenario has a revenue requirement of $18.5 million and the high cost scenario is estimated to be $36 million. The scenarios encompass a range of 25% below and 44% above the base case.

In Table 45 we also provide the approximate annual value of deferring the KEL line given the respective revenue requirement. We calculated these values using the methodology described in Section 3.2. For example, in the base case, the annual benefit of line deferral is approximately $1.49 million in present value revenue requirement. The values shown are the maximum possible incentive levels on a $/year basis for year one and are based upon the KEL avoided costs. In each subsequent year of deferral, we reduce the maximum incentive levels by the discount rate to account for the decreasing impact of additional deferrals on the present value revenue requirement.

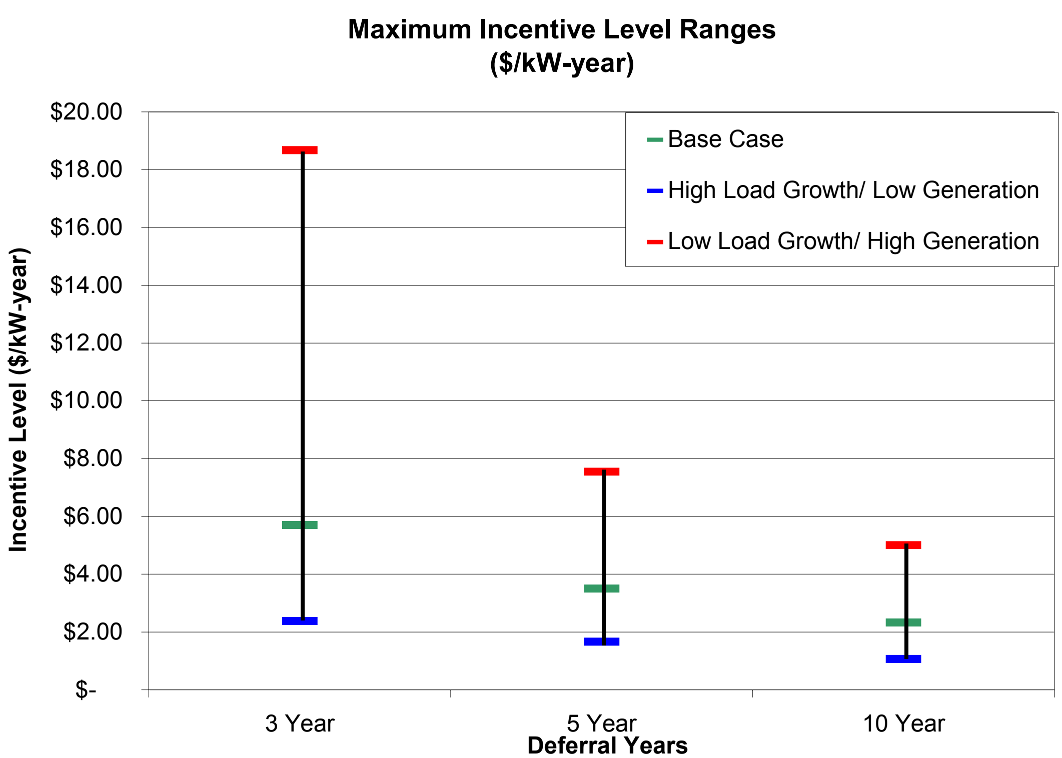
Table 24: Revenue Requirement Scenarios

Scenario	Revenue Requirement	Annual Deferral Benefit PV Revenue Requirement
Base Case	$25 million	$1.5 million
Low Cost	$18.5 million	$1.1 million
High Cost	$36 million	$2.1 million

7.2.2 Scenario Results for Incentive Payments

We calculated the maximum incentive level scenarios by combining the base case deferral value (based on a $25 million KEL cost) with the load reduction requirement scenarios using the avoided cost methodology described in Section 3.2. The resulting incentive level scenario ranges for the base case KEL line revenue requirements are shown in Figure 21.

Figure 21: Maximum Incentive Level Ranges with Required Load Reduction Scenarios



In Table 25, we show the range of maximum incentive payments for the complete range of sensitivities of load growth, generation operating, and KEL construction revenue requirement.

Table 25: Transmission Avoided Costs ($/kW at Covington)

Cost	Load	Generation	3 Year Deferral	5 Year Deferral	10 Year Deferral
B	B	B	$ 5.70	$ 3.50	$ 2.33
H	B	B	$ 8.13	$ 4.99	$ 3.32
L	B	B	$ 4.27	$ 2.62	$ 1.74
B	H	L	$ 2.38	$ 1.66	$ 1.07
B	H	B	$ 2.79	$ 1.84	$ 1.14
B	L	B	$ 11.38	$ 6.02	$ 4.32
B	L	H	$ 18.68	$ 7.54	$ 5.01
H	L	H	$ 26.61	$ 10.75	$ 7.13
L	H	L	$ 1.78	$ 1.24	$ 0.80

B=Base, H=High, L=Low

In addition to the incentive levels, we calculated the avoided line loss savings for all of the load reduction scenarios using the approach described in Section 3.3 (Table 26). This cost of deferring the line only applies to the Total Resource Cost (TRC) and Societal Cost Test. In the base and low cases of KEL revenue requirement scenarios, the avoided line losses are higher than the associated benefit of deferral. In the high case for KEL line revenue requirement, the avoided line losses are lower.

Table 26: Avoided Loss Savings for Each Load Reduction Scenario ($/kW at Covington)

Cost	Load	Generation	3 Year Deferral	5 Year Deferral	10 Year Deferral
B	B	B	$ 7.34	$ 4.51	$ 2.99
H	B	B	$ 7.34	$ 4.51	$ 2.99
L	B	B	$ 7.34	$ 4.51	$ 2.99
B	H	L	$ 3.06	$ 2.14	$ 1.38
B	H	B	$ 3.59	$ 2.37	$ 1.46
B	L	B	$ 14.65	$ 7.75	$ 5.56
B	L	H	$ 24.04	$ 9.71	$ 6.44
H	L	H	$ 24.04	$ 9.71	$ 6.44
L	H	L	$ 3.06	$ 2.14	$ 1.38

B=Base, H=High, L=Low

7.3 Market Price Sensitivity

To test the sensitivity of the cost-effectiveness results to market electricity prices, we developed low and high market electricity forecasts with natural gas prices unchanged at $3.81 per MMBtu. Varying the market price without changing the assumption of natural gas price results in a sensitivity to the ‘spark spread’ for natural gas-fired generation. A larger ‘spark-spread’ makes central station generation relatively more cost-effective. Even though these markets generally move together, we did not vary the fuel cost and the electricity price together because these scenarios would not materially change the results.

In Table 27 we list the assumptions used to develop the base, high, and low electricity price scenarios. Under the low forecast we assume that wholesale electricity prices are equal to the marginal operating costs (fuel costs and variable O&M) of a large-scale combined cycle power plant fueled by natural gas and a heat rate of 7,618 HHV MMBtu per kWh. This case results in a levelized market electricity price of $29.07 per MWh over the forecast period. This case is unlikely to persist in the long term since these electricity prices do not allow any margin to recover fixed operating costs.

Under the high forecast we assume that electricity prices are equal to the fully allocated cost of a simple cycle combustion turbine fueled by natural gas with a heat rate of 11,380 HHV MMBtu per kWh. This assumption results in a levelized electricity price of $52.26 per MWh during the forecast period.

Table 27: Electricity Price Scenario Assumptions

	Base Case	**Low Case**	**High Case**
Technology	Combined Cycle Combustion Turbine	Combined Cycle Combustion Turbine	Simple Cycle Combustion Turbine
Lifetime (yrs)	25	25	10
Fuel	Gas	Gas	Gas
Avg. Fuel Cost	$3.81	$3.81	$3.81
Capacity Factor	90%	90%	90%
Plant Costs Recovered in Power Prices			
Initial Cost ($/kW)	$523.06	$523.06	$369.90
Heat rate	7,618	7,618	11,380
Total Fixed Annual	$23.23	$0.00	$11.14
Fixed O&M ($/kW-yr.)	$18.00	$0.00	$7.44
Property Tax ($/kW-yr.)	$5.23	$0.00	$3.70
Variable O&M ($/MWh)	$0.60	$0.60	$0.12
Levelized Electricity Price	$40.03	$29.07	$52.26

7.4 Benefit/Cost Tests for Optimistic and Pessimistic Cases

The team recalculated the cost-effective of KEL alternatives for the ‘optimistic’ and ‘pessimistic’ scenarios. In Table 28, we show the combinations of input sensitivities we used to develop these cases. In the ‘optimistic’ case we assume a low growth forecast and high generation operating during the peak and the base case KEL revenue requirement which results in high avoided costs. In addition, we assume high market prices relative to the natural gas price that was held fixed during the scenario analysis. This is an ‘optimistic’ assumption since high electricity prices tend to make conservation measures more cost-effective and high electricity prices relative to natural gas prices tend to make generation more cost-effective.

In the 'pessimistic' case, we assume input sensitivities that tend to make KEL alternatives less cost-effective. In each case, we made the opposite assumption from the 'optimistic' case. Since there were no cost-effective measures in the base case, a set of more pessimistic assumptions does not change the fundamental results. However, we include the 'pessimistic' scenario to illustrate the relative impact of the input sensitivities to the cost-effectiveness of alternatives.

Table 28: Assumptions for 'Optimistic' and 'Pessimistic' Case

	'Optimistic' Case	'Pessimistic' Case
Load Forecast	Low	High
Generation Operating	High	Low
KEL Line Cost	Base	Base
Avoided Costs	High	Low
Market Price	High	Low

In addition to the load reduction requirements and the avoided cost sensitivities we describe above, we changed assumptions with respect to DSM and DR cost-effectiveness in the scenario analysis. In Table 29, we summarize the assumptions made for the DSM analysis. In each case we assume that participants are paid the full incremental cost of an efficiency improvement as an incentive. In the base case we assume that BPA pays 50% of the incentive, and that the local distribution utility pays the other 50%. In the 'optimistic' case we assume that the distribution utility pays the full incentive, and in the 'pessimistic' case we assume that BPA pays 100%. In addition, in the 'optimistic' case we assume that the impact of capacity reduction at the Covington substation is equal to the local distribution system impact rather than the capacity reduction on the system level adjusted by the load flow distribution factors.

Table 29: DSM Assumptions for Sensitivity Analysis

	Base	Optimistic	Pessimistic
Incentive Basis	100%	100%	100%
BPA % of Incentive	50%	0%	100%
Basis of kW Load Reduction	System	Local	System

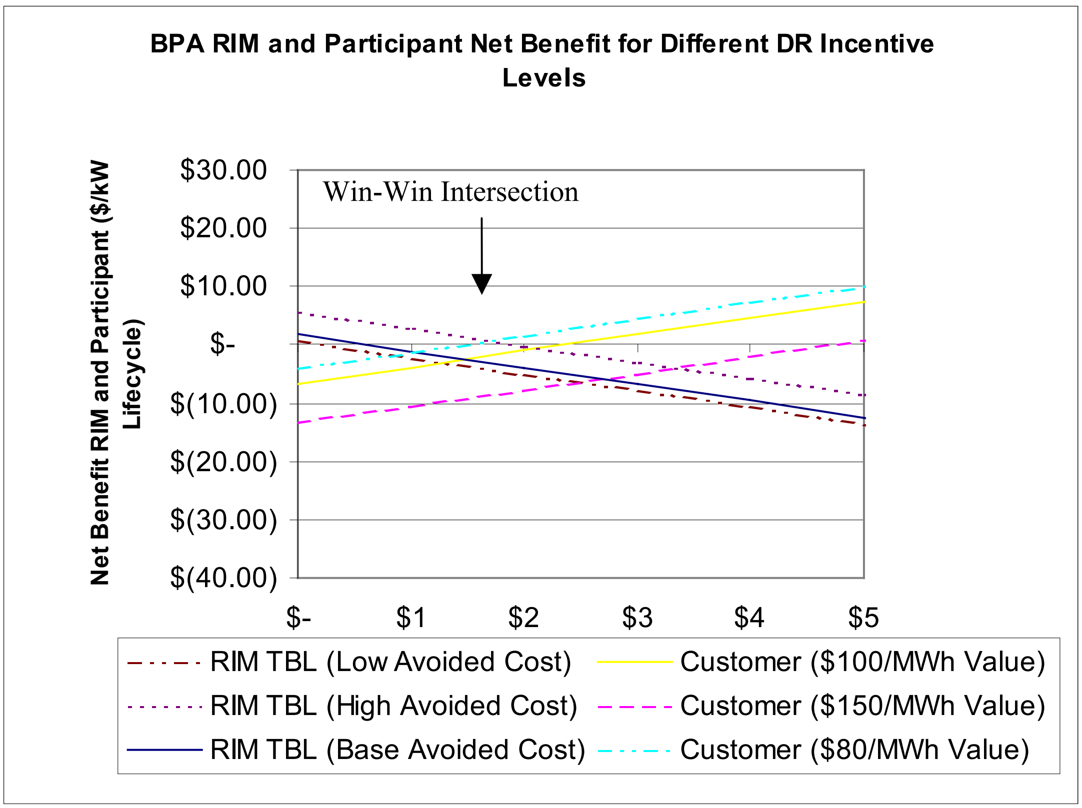
We computed the BC Ratios of each of the 1,533 DSM measures with the scenarios. The number of DSM measures that are cost-effective for each cost test is shown in Table 30. Even in the 'optimistic' case, there are no DSM measures that are cost-effective from the RIM BPA-TBL perspective. From this we conclude that even under extremely optimistic inputs, a conservation approach using DSM to defer the KEL line will raise TBL rates relative to construction of the new line. From a social perspective captured in the TRC and Societal cost tests, there are numerous measures that are cost-effective even under the 'pessimistic' scenario. From this we conclude that DSM is cost-effective to the region as a whole and should be pursued for reasons other than deferral of the KEL line.

Table 30: Number of DSM Programs that Are Cost Effective from Each Perspective

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Base	0	0	1034	1179	1523	1
Optimistic	0	0	1151	1263	1523	53
Pessimistic	0	0	929	1063	1523	0

The team also completed scenario analysis of demand response measures as an alternative to the KEL line. In Figure 22, below, we show the net benefit of demand response from the BPA TBL RIM and Participant cost tests for a range of scenarios.

Figure 22: BPA TBL Rim and Participant Net Benefit at Different DR Incentive Levels



If a DR program is cost-effective from both perspectives it should be possible to develop a DR program to contract for capacity reductions that lead to a relative reduction in TBL rates relative to the KEL line, and is attractive to potential customers. On the horizontal axis we show the incentive level paid to customers in $/kW-year, and on the vertical axis we show the net benefit of the program over the assumed 3-year life of the DR program. As the incentive payments are increased, the benefit to TBL rates decreases and the benefit to the participants increase. Any intersection of the two perspectives above the zero net benefit line demonstrates potential for DR. Across the range of scenarios that we examined, this 'win-win' intersection occurs with the avoided costs developed for the 'optimistic' scenario and a low value to the participating customer of reduced energy consumption during the program of $80/MWh. In the base and 'pessimistic' cases we did not find a 'win-win' intersection for DR.

We developed Table 31 and Table 32 to summarize our analysis of BC ratios for each of the alternatives. The tables show the BC ratios, from each of the stakeholder perspectives, for the measure with the highest RIM BPA-TBL level. As discussed above, we did not find any cost-effective DSM measures from the TBL RIM perspective in either case. Similarly, we did not find any DG technology that was cost-effective from the TBL RIM perspective in either scenario. However, as we illustrated above, DR can be cost-effective from both the RIM and Participant cost levels in the 'optimistic' case. This finding for DR is very sensitive to the assumed loss in value for a customer to participate in the program. In addition, because of the avoided line loss savings, DR is not cost-effective from the TRC and societal cost tests. Large-scale generation is cost-effective in the 'optimistic' case because of the assumption of high electricity market prices.

Table 31: Benefit Cost Ratio of Alternative with the Highest TBL RIM BC Ratio: 'Optimistic' Case

	DSM	DG	DR	G
Alternative	HEATING - Single Family Heat Pump - PTCS System O&M	Gas Spark Ignition	BPA (Conceptual)	Combined Cycle Combustion Turbine
RIM-BPA/TBL	0.12	0.02	1.00	1.00
Utility Cost	No Utility Costs	1.00	1.00	1.00
TRC Cost	1.13	0.73	0.70	2.03
Societal Cost	1.33	0.66	0.73	1.44
Participant Cost	2.27	0.56	1.14	1.30
RIM-LDC	0.54	1.28	1.05	Not Effected

In Table 32 we provide the BC ratios for the 'pessimistic' case. As discussed earlier, none of the alternatives are cost-effective from the TBL RIM perspective in this scenario. However, even in the pessimistic scenario, we find that DSM measures are cost-effective from the TRC and societal cost perspectives.

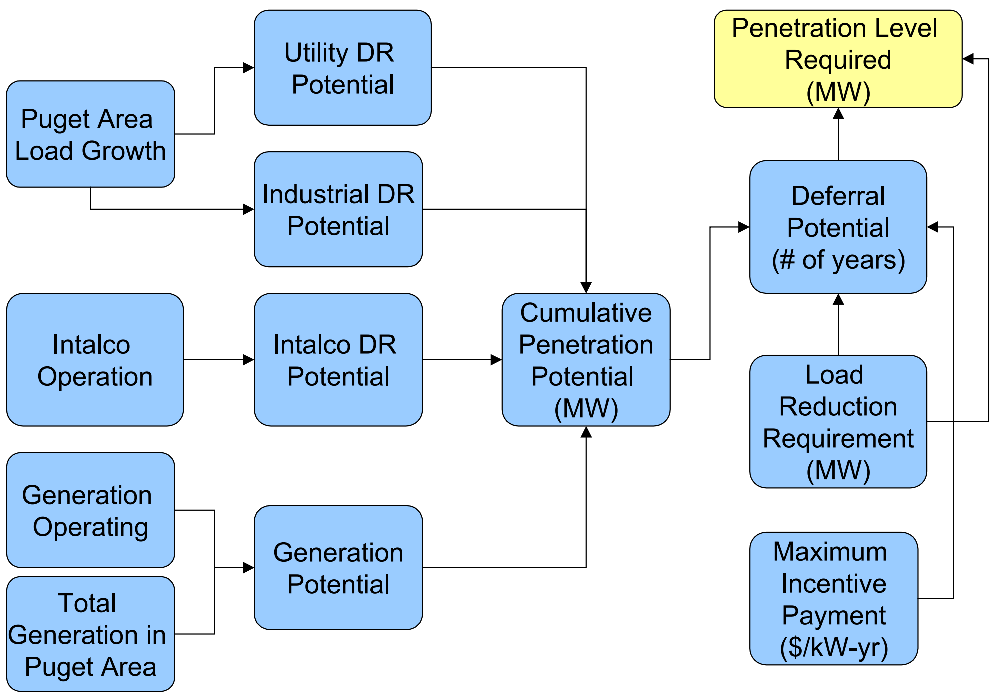
Table 32: Benefit Cost Ratio of Alternative with the Highest TBL RIM BC Ratio: 'Pessimistic' Case

	DSM	DG	DR	G
Alternative	HEATING	Gas Spark Ignition	BPA (Conceptual)	Combined Cycle Combustion Turbine
RIM-BPA/TBL	0.00	0.00	1.00	1.00
Utility Cost	0.00	1.00	1.00	1.00
TRC Cost	1.65	0.41	0.23	1.13
Societal Cost	2.04	0.37	0.25	0.80
Participant Cost	2.20	0.56	0.37	0.72
RIM-LDC	0.56	0.82	0.58	Not Effected

Section 8. Penetration Analysis

The team conducted a penetration analysis to determine whether or not the alternatives could meet the required level of load reduction within the necessary time frame. Figure 23 shows the relationships of the factors we incorporated into the penetration analysis. After estimating the cumulative penetration potential for the Puget Sound area, we calculated the required penetration level to achieve the required load reduction required for each year. This was completed for each of the scenarios described in Section 7.

Figure 23: Required Penetration Level Calculation Process Flow



8.1 *Total Potential Market of Potentially Economic Alternatives*

8.1.1 Estimate of Potential Penetration of DR/DLC Alternatives

The overall estimate of the potential market for industrial DR/DLC is shown below in Table 33. We did not include the commercial and residential sectors in this penetration analysis. Given the short time frame, which requires implementation prior to the winter of 2003-2004, targeting the less dispersed and larger industrial customers would likely yield better results for BPA's load reduction goal at Covington. There are approximately 1,380MWs of industrial Puget Sound area load that could be targeted with a DR/DLC program. However, this potential is reduced to a 444MW reduction at Covington when load flow effects are applied using the load flow distribution factors. Given the same load flow factor, Intalco could contribute up to 150MW of load relief at Covington if it were able to curtail its entire load. However, due to its operational characteristics, Intalco can only curtail approximately 50% of its load, thus Intalco is capable of providing 75MW of load relief. The maximum potential penetration level from the DR/DLC alternatives we analyzed in the industrial sector is estimated to be 519MW. This value is based upon area industrial customers and the Intalco facility.

Table 33: Base Case Potential Market for DR/DLC Measures

Sector	Puget Sound Area Peak Load	Covington Load Flow Factors	Approx. Covington Transformer Peak Contribution
	MW	*%*	*MW*
Industrial Customers	1,380	32	444
Intalco	468	32	75
Total MW			**519**

8.1.2 Estimate of Potential Penetration of Generation Alternatives

In Table 34, we provide the base case potential for operation of large-scale generation to reduce loads on the Covington transformer. To develop a penetration estimate of existing generation, we assumed that all existing generators would be available, except for Ross Dam, which is likely to provide additional output during a sustained extreme weather event. Thus, a total of 277MW of generation would be available, yielding a 70MW reduction on the Covington transformer banks by applying the load flow distribution factors. Generators that are not yet online and producing energy were excluded from the base case. Phase 1 generation refers to those that are under construction. Phase 2 refers to those generators that have been permitted.

Table 34: Base Case Penetration Market for Generation

	Puget Sound Area Maximum Availability	Approx. Covington Transformer Peak Contribution	Penetration Achieved	Potential MW for Covington Load Reduction
	MW	MW	%	MW
Existing G	277	70	100%	70
Phase 1 G	268	56	0%	-
Phase 2 G	1,156	365	0%	-
Total				**70**

8.2 Range of Required Penetration across Scenarios

8.2.1 DR/DLC Program Required Penetration

Table 35 shows the penetration required from DR/DLC measures (including an Intalco curtailment contract) to meet the potential overloads for each of the five scenarios of load growth described in Section 7.1. The total MW reductions required for each scenario are shaded gray. In each case, we allocated load relief between Intalco and industrial customers in order to reach this target. We assumed that any MWs reduced from either the Industrial segment or Intalco are additive, thus for the base case in Year 1 the combined reduction of 47MW plus 75MW would reach the 122MW required reduction.

Table 35 indicates that by Year 3, there is not enough existing industrial load impact at Covington in the high load growth scenarios. However, in the low load growth scenarios, the Year 1 required penetration levels appear achievable if a contract is signed with Intalco to commit to curtail the maximum level they are able to achieve.

Table 35: Required DR/DLC Penetration Levels for Load Growth Scenarios[23]

Scenario	DR Penetration	Year 1		Year 2		Year 3	
		% Penetration Required	MW	% Penetration Required	MW	% Penetration Required	MW
Base Case		**122**		**190**		**269**	
	Industrial	11%	47	26%	115	44%	194
	Intalco	100%	75	100%	75	100%	75
High Load Growth/ Low Generation		**346**		**488**		**645**	
	Industrial	61%	271	93%	413	Not Enough Available	
	Intalco	100%	75	100%	75		
					488		
High Load Growth/ Base Generation		**252**		**394**		**551**	
	Industrial	40%	177	72%	319	Not Enough Available	
	Intalco	100%	75	100%	75		
Low Load Growth/ Base Generation		**58**		**91**		**135**	
	Industrial	0%	-	4%	16	14%	60
	Intalco	100%	75	100%	75	100%	75
Low Load Growth/ High Generation		**5**		**39**		**82**	
	Industrial	0%	-	0%	-	2%	7
	Intalco	100%	75	100%	75	100%	75

8.2.2 DR/DLC Program and Existing Generation Required Penetration

Reviewing deferral possibilities with DR/DLC programs only represents a single alternative solution for the deferral and is not a comprehensive method for evaluating all of the potential alternative solutions. A combined solution would incorporate a combination of demand response and generation measures. Therefore, we looked into the possibility of achieving the load reduction targets by employing a combination of existing generation and DR/DLC programs. Table 36 displays the penetration levels required of generation and DR/DLC for the five load scenarios analyzed. Load reduction at Intalco is assumed to be phased in first, followed by existing generation, and then demand response programs. This approach utilizes the 'chunks' of

[23] Intalco contributions do not vary because BPA would either have a contract with Intalco or not. If a contract is secured, we assume that it would be for the maximum level for which Intalco can reduce its load, equal to 75 MW of effective load reduction at Covington.

capacity from largest to smallest. For example, Intalco is assumed to contribute all of its available effective load reduction at Covington before the available existing generation would be targeted. Once the existing generation resources reach their maximum contribution of 70MW at Covington, DR-DLC programs would be implemented. Realistically, these three resources would be simultaneously implemented; however, the phased-in approach shown here is useful conceptually.

Table 36: Required DR/DLC and Existing Generation Penetration Levels for Load Growth Scenarios

Scenario	DR & Generation Penetration	Year 1		Year 2		Year 3	
		% Penetration Required	MW	% Penetration Required	MW	% Penetration Required	MW
Base Case		**122**		**190**		**269**	
	Industrial	0%	-	10%	45	28%	125
	Intalco	100%	75	100%	75	100%	75
	Generation	68%	47	100%	70	100%	70
High Load Growth/ Low Generation		**346**		**488**		**645**	
	Industrial	45%	201	77%	343	Not Enough Available	
	Intalco	100%	75	100%	75		
	Generation	100%	70	100%	70		
High Load Growth/ Base Generation		**252**		**394**		**551**	
	Industrial	24%	107	56%	249	92%	406
	Intalco	100%	75	100%	75	100%	75
	Generation	100%	70	100%	70	100%	70
Low Load Growth/ Base Generation		**58**		**91**		**135**	
	Industrial	0%	-	0%	-	0%	-
	Intalco	100%	75	100%	75	100%	75
	Generation	0%	-	24%	16	86%	60
Low Load Growth/ High Generation		**5**		**39**		**82**	
	Industrial	0%	-	0%	-	0%	-
	Intalco	100%	75	100%	75	100%	75
	Generation	0%	-	0%	-	11%	7

Combining the G and DR/DLC resources does appear to provide enough potential penetration for deferral in Year 1, as well as sufficient load reduction in the low load growth scenarios. While this is an improvement upon the DR/DLC single-resource penetration estimates shown in Table 35, by Year 2 of the base case, BPA would need to secure Intalco's total load reduction contribution, all available existing generation in the area, and achieve a 10% penetration level with DR/DLC programs.

8.3 Penetration Feasibility

8.3.1 Benchmarking Utility DR/DLC Programs

In order to ascertain whether the required penetration levels are reasonable for BPA to achieve, the team conducted a high-level benchmark study of utility DR/DLC programs targeted toward the commercial and industrial sectors. The first four data columns in Table 37 below list name, incentive, number of months, and hours per year of current or historical utility DR/DLC programs. The hours per year column indicates the maximum hours for which the program was designed to operate or the total number of hours that curtailment/interruption was achieved. In some cases, such as price-dispatched programs like BPA's Demand Exchange, no upper bound was indicated. For these programs, we assumed an average of 100 hours per year.

In all cases the duration of the program (number of months or hours per year required) differed from BPA's estimated duration of 3 months and only 10 hours in Year 1 of potential required load relief. The last column in this table shows what the incentive levels would look like if the BPA duration characteristics were applied to each program. We estimated that since the program would be required for fewer hours, BPA may be able to achieve their required reduction with lower incentive payments.

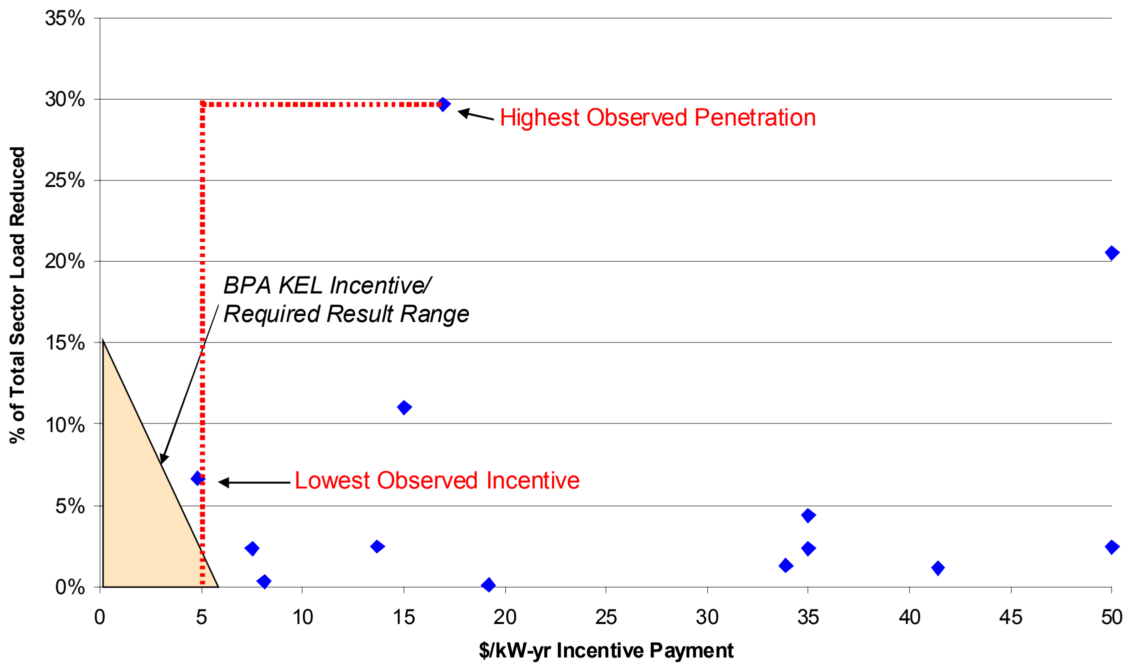
Table 37: Survey of Utility DR/DLC Program Characteristics

	Program Type	Program Incentive ($/kW-yr)	# Months	# Hours /Year	Calculated BPA Incentive ($/kW-yr)*
1	Demand Buy Back	16.95	12	113	1.5
2	Energy Exchange Program	4.8	12	48	1
3	Voluntary Load Reduction	15	4	100	1.5
4	Interruptible Option	41.68	4	100	24.3
5	Curtailable Option	32.4	4	75	20.7
6	Curtailable Option	27.6	4	75	35
7	Curtailment Service Cooperative	35	3	120	30
8	Interruptible Service	120	12	300	65
9	Demand Relief Program	128	4	96	5
10	Emergency Demand Response Program	50	6	100	0.81
11	Day-Ahead Demand Response Program	8.1	6	100	3.5
12	Demand Bidding Program	35	12	100	21
13	Com/Ind. Base Interruptible Program	84	12	120	1
14	Scheduled Load Reduction Program	19.2	4	192	5
15	Emergency Response Program	50	12	100	10.35
16	Capacity Program - Interruptible Tariff	41.4	12	300	10.35
17	Economy Program - Interruptible Tariff	41.4	12	300	4.75
18	Reliability Program	63	12	150	1.37
19	Demand Exchange	13.7	6	100	0.0

Figure 24 illustrates the levels of load reduction other utilities achieved through their DR/DLC programs as a percentage of the sector they were targeting and the incentive levels they were offering. The triangle in the lower left-hand corner represents the range of incentives that BPA would be able to offer to obtain the required load penetration. The penetration targets are unknown and each program has its own unique goals, but we conclude from the clustering of the programs below the 5% penetration range that DR/DLC programs would not achieve high penetration levels with very low incentives. If this were possible for BPA, the capacity program would be unique among this set of similar programs.

Since the incentive levels that BPA is able to offer are so low, it would be difficult to implement an effective DR/DLC program relying solely on incentive payments as motivation for participation. Any DR-DLC program designed to meet the load relief needs at Covington would need to achieve higher penetration with a lower incentive level than the programs we observed in our survey.

Figure 24: Penetration and Incentive Ranges of 13 Utility DR Programs



8.3.2 Generation Penetration Feasibility

Table 38 lists both the existing and potential large generators in the Puget Sound area. Only the existing facilities shown in this table were included in the penetration analysis. The Ross Dam is not included in the overall estimates of available generation because it is unlikely that in the event of a multi-day Arctic Express weather system this facility would be able to generate. With the exclusion of the Ross Dam, there are four remaining facilities that could contribute additional generation and provide load relief during the extreme peak period in question.

In the above analysis, we assumed that it would be possible to put generation contracts in place up to the maximum potential generation level for these facilities. However, there is uncertainty with regard to how firm the available capacity values listed in Table 38 are in both the short and long-term. For example, it was recently announced by TransAlta that the largest potential contributing plant, Pierce Power, is scheduled to be removed from service. This plant was originally commissioned in 2001 to improve the power shortage in the Pacific Northwest.[24]

[24] "TransAlta decommissions temporary Pacific Northwest plant" News Release at www.transalta.com

Table 38: Existing and Potential Large Generators in the Puget Sound Area

Project	Location	Type	Available Capacity (Local MW)*	Effective MW at Covington
In service			*277*	*70*
Pierce Power	Frederickson	Gas turbine	154	31
Ross Dam**	Skagit River	Hydroelectric	109	46
BP Cherry Point GTs	Blaine	Gas turbine	73	23
Equilon GTs	Anacortes	Gas turbine	39	12
Georgia-Pacific GT	Bellingham	Gas turbine	11	4
Construction (Phase 1)			*268*	*56*
Frederickson Power 1	Frederickson	Combined-cycle	249	50
Tesoro (Permanent ICs)	Anacortes	Reciprocating engine	19	6
Permitted (Phase 2)			*1,156*	*365*
Sumas Energy 2	Sumas	Combined-cycle	660	211
Everett Delta I	Everett	Combined-cycle	248	77
Everett Delta II	Everett	Combined-cycle	248	77
Potential (Phase 3)			*1,643*	*460*
BP Cherry Point Cogen.	Blaine	Cogeneration	720	230
U.S. Electric Cherry Point	Blaine	Coal–Steam	349	112
Frederickson Power 2	Frederickson	Combined-cycle	280	56
Tahoma Energy Center	Frederickson	Combined-cycle	270	54
Cedar Hills	Cedar Hills Landfill	Landfill Gas	24	7
Maximum Available Puget Sound Area Generation			***3,453***	***950***

* Includes only capacity that is not already assumed to be operating in BPA's load flow studies.
** Ross Dam is unlikely to be available during a multi-day Arctic Express event.

For three of the five scenarios, securing the potential generation resources currently available, combined with DR/DLC program load relief, would enable BPA to defer the KEL line construction for at least one year. Obtaining a contract with Intalco would be the primary determining factor in the success of any deferral effort. If BPA were able acquire 50% of the available generation and achieve a 2% penetration within the industrial sector, line construction could be deferred for the first year in the base case. Beyond Year 1, however, it would be difficult for BPA to achieve the levels of penetration necessary to reach the load reduction targets in the base case due to the low incentive levels BPA is able to offer for DR/DLC and the limited generation resources available in the area.

Section 9. Conclusion

This study provides a high-level economic screening analysis of potential alternatives to the KEL transmission line. The analysis consisted of a pre-assessment of the load reductions required from alternatives in order to defer or replace the KEL line. Following the pre-assessment of performance requirements, the economic screen comprised three steps. Step 1 was an assessment of the cost-effectiveness of alternatives given the potential avoided costs of deferring the line and estimates of the cost of alternatives. Step 2 was a scenario analysis to test the sensitivity of cost effectiveness results to changes in key economic input assumptions. Step 3 was to estimate the potential penetration of alternatives to determine whether or not sufficient load reduction could be obtained.

An assessment of the transmission capacity requirements to reliably serve the Puget Sound Area, carried out in conjunction with the BPA Transmission Business Line (BPA TBL) team, gave an estimate of 122MW of load reduction required at the Covington substation for approximately 10 hours during the 2003-2004 winter. The required load reduction and the number of forecasted hours of Covington Transformer overload increases in each year thereafter. Our estimate of the base-case load reductions and number of hours required are provided in Table 39, below. These overload forecasts depend on the load growth forecasts, the generation operating in the area, and the requirements of the Canadian Entitlement Return.

Table 39: Projected Covington Transformer Bank Overloads, 2004-2013

Year	Maximum Overload (MW)	Number of Hours Overload Occurs
2004	122	10
2005	190	17
2006	269	30
2007	397	51
2008	449	61
2009	505	70
2010	558	86
2011	611	102
2012	664	119
2013	714	135

A large number of potential alternatives were evaluated including a wide range of DSM measures, small-scale generation, large-scale generation, demand response, and direct load control. The economics of each approach were evaluated from the perspective of each of the major stakeholders including BPA TBL, the participant in the program, the local distribution utility, as well as the more social perspectives provided by the Total Resource Cost test and the Societal Cost Test.

Under base case economic assumptions and using the criterion, the same or lower rates, the KEL line is the most cost-effective solution to regional capacity constraints. In addition, we analyzed the cost-effectiveness and penetration potential with combinations of ‘optimistic’ and ‘pessimistic’ assumptions. The KEL line remained the most cost-effective alternative in the ‘pessimistic’ case. In the ‘optimistic’ case, our analysis concludes that demand-response type programs and contracting with existing in-area generators to operate during the critical peak loads would be cost-effective. In addition, our penetration analysis of these technologies in the ‘optimistic’ scenario demonstrates that it would be feasible to achieve sufficient penetrations to defer the line for at least three years. Therefore, there is potential for alternatives in the ‘optimistic’ case.

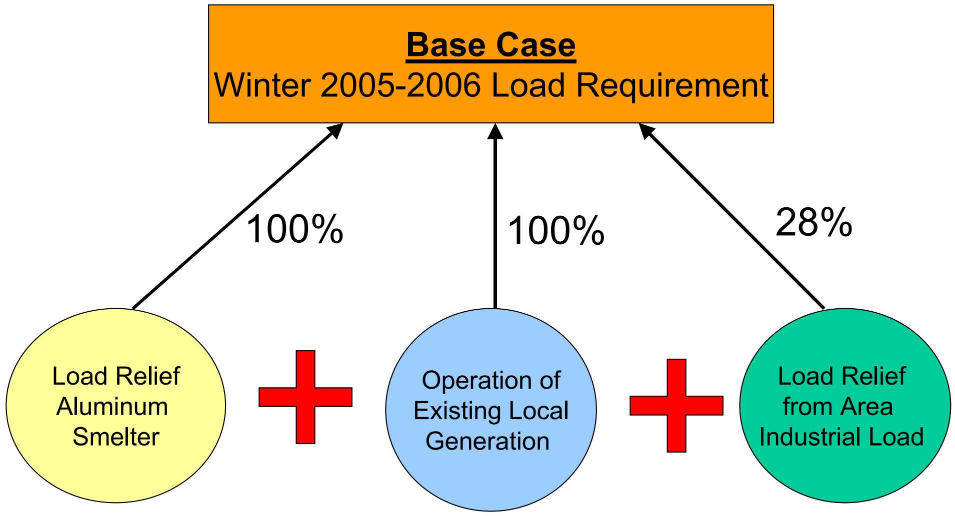
Based on our analysis we make the following findings:

A high level of load reduction or additional generation is required to defer KEL. Based on the planning assumptions provided, the level of load reduction required to prevent an overload on the transmission system and to maintain system reliability during a major system outage is approximately 122 megawatts (MW) at the Covington transmission substation during the winter of 2003-2004. This load reduction requirement amount increases every year thereafter. The analysis of the load requirement in Section 4 provides a thorough description of the load forecasting process.

The Puget Sound Area peak load is approximately 12,000MW. Because of the way that power flows over the network of transmission facilities, each MW of load reduction or additional in-area generation only reduces the flows across the Covington transformer by a fraction of a MW. For example, a 100MW load reduction in downtown Seattle will only reduce loadings on the Covington transformers by 42MW, while the same reduction in Tacoma would only achieve a 20MW reduction at Covington. The ratio of the MW change at Covington to the MW change at the source is called the load flow distribution factor (or distribution factor). When applying these factors, the 122MW that are required to bring the peak load of Covington below overload levels in the first year translates to approximately 381MW of load reduction or additional generation within the Puget Sound Area assuming a distribution factor of 32%[25]. Thereafter, the amount of load reduction or additional generation needed to prevent an overload increases annually. By the winter of 2005-2006 the needed amount grows to 269MW at Covington, or 841MW within the Puget Sound Area. As illustrated in Figure 1, a 3-year deferral of the line would require 100% of the available load relief from the large aluminum smelter in the area, plus operation of all existing generation not expected to be on-line, plus load relief from 28% of industrial load in the area. To put the 28% industrial participation rate in perspective, we reviewed information from 13 utility DR programs, and found only four with participation rates above 5%.

[25] 32% is the load weighted average distribution factor across the Puget Sound study area.

Figure 25: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Base Case Assumptions)



Transmission avoided costs are low. The avoided cost of the KEL project, assuming a cost of $25 million and annual operations and maintenance (O&M) costs of $50,000 for the line, is approximately $1.49 million per year (as calculated using the differential revenue requirement method described in Section 3.2 of this report). Therefore, in order to prevent increasing TBL's revenue requirement, 122MW of demand reduction at Covington would have to be purchased for $1.49 million or less. This equates to approximately $12.25 per kW at Covington per year or $3.92 per kW-year in the Puget Sound Area based on average load flow distribution factors.

Furthermore, TBL estimates that construction of the KEL line would reduce peak losses on the transmission system by 11MW. This would result in annual energy savings of 48,180MWh, valued at nearly $2 million dollars.[26] Therefore, the economic value of the energy savings is greater than the benefit of deferring the line.

Incentive Levels are low compared to other programs. The likelihood of achieving significant penetration in the area with incentive levels calculated from the avoided cost of deferring the KEL line cannot be determined precisely without a detailed customer assessment. To provide BPA with some general indication, however, we compared incentive levels and penetration rates for 19 demand response programs across the United States with the incentive levels and penetration rates required for cost-effective deferral of the KEL line. From this comparison we conclude that it is unlikely the available incentive payments based on the value of deferring the KEL line would be sufficient to achieve the significant penetration required in this case. Any DR-DLC program designed to meet the load relief needs at Covington would need to achieve higher penetration with a lower incentive level than the programs we observed in our survey.

Demand response is the most cost-effective alternative from a TBL rate perspective. Of the alternatives considered, we found that demand response programs are most likely to be cost-effective from the utility rate perspective and to participants. Demand response is well suited to

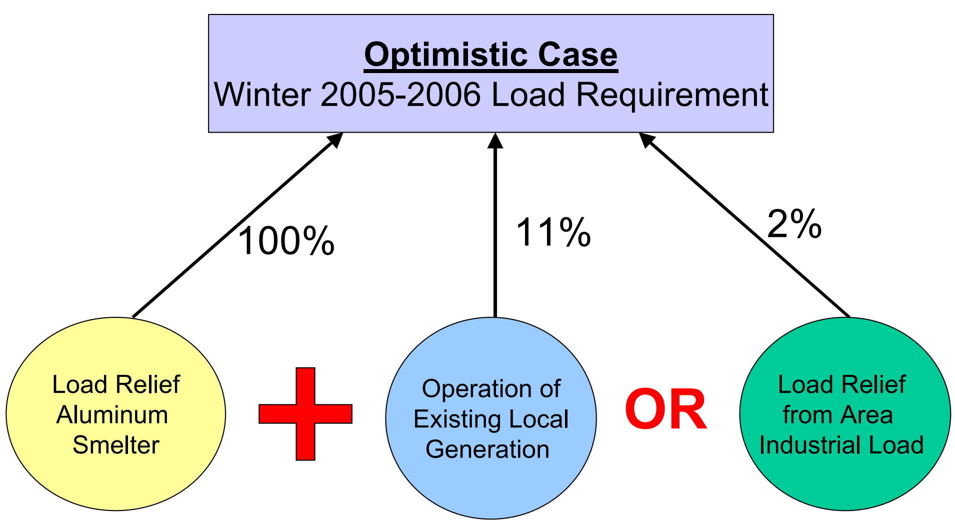
[26] Assumes the 'base case' market price of $40.03 /MWh.

solving the capacity problem without causing significant revenue loss since it focuses load reduction on only the hours when needed for system reliability. We found, however, that demand response is not cost effective from the TRC perspective because deferral of the line would eliminate the significant loss savings BPA expects the line to achieve. DSM is cost-effective from a TRC perspective, but is not likely to produce win-win outcomes because there would be increased pressure on rates due to increased efficiency, and subsequently reduced utility sales throughout the year or season. We found that DSM programs would need to reduce energy each year from half to one and a half times the annual energy growth. Also, DSM efforts would either have to be funded externally to BPA or the additional costs would have to be passed through to TBL's ratepayers, because the DSM measures do not pass TBL's RIM test.

Scenario analysis indicates alternatives could be cost effective if demand is lower than forecast. To provide BPA with a comprehensive assessment of the potential for cost effective alternatives to the KEL line, we conducted a scenario analysis. The purpose of the analysis was to evaluate the sensitivity of cost effectiveness results to changes in key economic inputs. We tested the entire range of alternative technologies under three sets of economic assumptions. These included the base case which we largely derived from BPA's transmission planning work, an 'optimistic' case that improves the cost-effectiveness and penetration requirements of alternatives, and a 'pessimistic' case that reduces the cost-effectiveness of alternatives. The base case represents our best estimate of the future, and the 'optimistic' and 'pessimistic' cases represent extremes that have a low probability of occurring. We found the KEL line was the most cost-effective solution to capacity constraints in both the base and pessimistic cases. In the optimistic case, we found DR and generation were cost effective from both the ratepayer and participant perspectives.

In this optimistic case we estimated that BPA would require 82MW of load reduction at the Covington substation to defer the line for 3 years or 256MW within the Puget Sound Area. As illustrated in Figure 2, this can be achieved through 100% of available load relief from the large aluminum smelter in the area, plus either operation of 11% of existing generation not expected to be on-line or load relief from 2% of industrial load in the area.

Figure 26: Load Relief and Generation Requirements for a 3-Year Deferral of the KEL Line (Optimistic Assumptions)



9.1 Summary

The decision whether to build the line or defer the line depends on expectations of demand and the availability of funds for alternatives. Three scenarios were examined to provide insight into this decision. If demand increases at the forecasted rates and funds for alternatives are limited to the value of deferring the line, then the KEL line is the most cost effective and feasible solution. However, if demand is significantly lower than expected, then sufficient load reduction potential of alternatives exists to mitigate the need for the line. In this case, the economics of alternatives are also improved, and it may be possible to defer the line for up to 3 years with demand response programs and contracts with existing generation in the area. Likewise, if additional benefits of alternatives can be found to offset the costs such as through partnering with local distribution utilities, the cost-effectiveness of alternatives can be improved. On the other hand, if demand increases at a higher rate than forecasted, then the KEL is again the most cost effective and feasible solution.

There are competing views of the appropriate criterion for cost effectiveness. The principal debate is between the Ratepayer Impact Measure (RIM) and the Total Resource Cost test (TRC). RIM compares the effect on TBL's rates of the cost of alternatives versus the capital and maintenance costs of a proposed solution. TRC compares the costs and benefits of alternatives with all the costs and benefits of a proposed solution. TRC includes energy and generation benefits. An alternative deemed cost effective under TRC could cause rates to be higher. While our analysis provides information to use in evaluating these two criteria, it was not intended to provide guidance as to the appropriateness of one over the other.

Independent of BPA's decision regarding the KEL line, the distribution system benefit of alternatives is an avenue of additional investigation that was not within the scope of this project, but should be pursued. If distribution benefits are significant, they would increase the value of alternative measures and should provide an additional source of funding. The above are institutional and policy considerations that are beyond the scope of this analysis and will require more time for resolution than is available relative to the KEL line decision process.

Section 10. Appendix 1: DSM Results

Table 40: Base Case Results: Best RIM-BPA/TBL BC Ratio Measure for Each Sector and End Use

Sector	End Use	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Single Family	Heating	0.0042	0.02	1.94	2.40	2.20	0.71
Commercial	Heating	0.0039	0.01	1.17	1.28	1.25	0.77
Industrial	Motors	0.0033	0.09	146.16	202.18	142.95	0.87
Grocery	Lighting	0.0032	0.01	1.67	1.91	1.70	0.86
Restaurant	Lighting	0.0024	0.01	1.60	1.83	1.71	0.80
Single Family	Lighting	0.0022	0.01	5.03	6.15	8.18	0.71
Multifamily	Envelope	0.0019	0.00	3.65	7.38	4.14	0.66
Single Family	Appliances	0.0019	0.01	1.05	1.07	1.09	0.76
Other	Traffic Signals	0.0019	0.00	1.60	1.93	2.82	0.70
Other	Vending Machines	0.0013	0.00	2.11	2.75	3.12	1.02
Single Family	Water Heating	0.0013	0.00	1.12	1.19	1.29	0.71
Other	Exit Signs	0.0011	0.00	1.73	2.25	2.91	0.65
Office	Envelope	0.0010	0.00	2.22	4.00	2.70	0.66
Multifamily	Appliances	0.0002	0.00	1.05	1.18	1.56	0.76

- HEATING - Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP w/PTCS - Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS
- HEATING - Commercial Small Heat Pump - Heat pump rated HSPF 8.0 and SEER 13 or higher
- MOTORS - New Premium Efficiency Open Drip-Proof (ODP) Industrial Motors, 100 - 250 HP - Premium Efficiency 15 HP 1800 RPM ODP
- LIGHTING - Grocery, HtPmp Heat - 2-F32T8 32watt T8 lamp(s) w/ IS Elect. ballast
- LIGHTING - Restaurant, Gas Heat - 2-F32T8 32watt T8 lamp(s) w/ IS Elect. ballast
- LIGHTING - Residential Lighting - Energy Star CFL Exterior - 26 Watt
- ENVELOPE - New Low Rise (Less than 5 Stories) Multifamily Dwellings w/Electric Heat - Long Term Super Good Cents Program & Specifications
- APPLIANCES - Single Family Residence w/Electric Water Heat - Energy Star Dishwasher - Electric DHW
- TRAFFIC SIGNALS - Existing and new traffic signals - LED Traffic Signals - Replace 12 inch Red Incandescent Left Turn Bay with 12 inch Red LED module
- VENDING MACHINES - Existing and new vending machines with illuminated fronts - Vending Machine Controller-Large Machine w/Illuminated Front

- WATER HEATING - Residence w/Electric Water Heat - EF- 0.91 Domestic Water Heater w/80 gallon rated capacity and minimum 10 year warranty
- EXIT SIGNS - Building or structure where exit signs are required - Energy Star Light Emitting Diode (LED) Exit Sign - Incandescent Exit Sign Base Case Fixture
- ENVELOPE - Small Office Weatherization Floor Insulation - R0 > R19 batt
- APPLIANCES - Multifamily common area or commercial Laundromat w/Electric Dryer and Electric Water Heat - Energy Star Clothes Washer - Commercial Laundry - Electric Water Heater & Dryer

Table 41: High Case Results: Best RIM-BPA/TBL BC Ratio Measure for Each Sector and End Use

Sector	End Use	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Residential	HEATING	0.12182	No Costs	1.1263918	1.32622	2.271919	0.537287
Residential	ENVELOPE	0.0756	No Costs	0.7734072	0.778167	1.019761	0.081233
Retail	LIGHTING	0.05242	No Costs	1.4190025	1.644883	2.264875	0.643189
Commercial	ENVELOPE	0.04769	No Costs	1.3346391	1.499764	1.313166	0.903818
Residential	AC	0.04505	No Costs	0.9596437	1.359056	1.808506	0.484423
Other	TRAFFIC SIGNALS	0.03756	No Costs	2.671951	3.157824	3.917702	0.732854
Commercial	APPLIANCES	0.03366	No Costs	2.4164582	4.216765	2.417784	0.714741
Residential	WATER HEATING	0.02759	No Costs	0.7051603	0.737292	1.123673	0.298116
Residential	LIGHTING	0.0252	No Costs	1.0666137	1.085855	1.079922	0.88704
Commercial	HEATING	0.0233	No Costs	1.187743	1.263433	1.289272	0.77522
Commercial	EXIT SIGNS	0.0233	No Costs	1.358093	1.712916	2.148293	0.5969
Industrial	MOTORS	0.0233	No Costs	2.6907709	3.388458	3.118524	1.057349
Residential	APPLIANCES	0.02048	No Costs	7.188171	8.40871	27.19212	0.19031
Other	VENDING MACHINES	0.02048	No Costs	6.7119553	7.790815	26.51209	0.172715
Commercial	LIGHTING	0.0177	No Costs	19.347523	25.94088	14.94159	1.059835

- HEATING - Single Family Heat Pump - PTCS System O&M
- AC - Residential Dwellings - Energy Star Window Air Conditioner - 16000 Btu/hr
- TRAFFIC SIGNALS - Existing and new traffic signals - LED Traffic Signals - Replace Large Pedestrian Incandescent " Don't Walk" with Large LED Module
- HEATING - Retail Small Heat Pump - Heat pump rated HSPF 8.0 and SEER 13 or higher
- ENVELOPE - Single Family Weatherization - Infiltration Control (Cost and Savings per sq. ft. of floor area for each 0.1 ach reduction) - Mechanical ventilation systems must be installed in substantial compliance with Appendix T, Part 2 in all homes for which verified reductions in air infiltration/exfiltration are claimed.
- LIGHTING - Residential Lighting - Energy Star CFL Exterior - 23 Watt
- ENVELOPE - Small Retail Weatherization Wall Insulation - R0> R11 blown

- APPLIANCES - Multifamily common area or commercial Laundromat w/Gas Water Heat and Electric Dryer - Energy Star Clothes Washer - Commercial Laundry - Electric Dryer/Gas Water Heater
- APPLIANCES - Single Family Residence - Unknown DHW Energy Source - Energy Star Dishwasher - Gas DHW
- WATER HEATING - Residence w/Electric Water Heat - EF- 0.91 Domestic Water Heater w/80 gallon rated capacity and minimum 10 year warranty
- EXIT SIGNS - Building or structure where exit signs are required - Energy Star Electro-luminescence (EL) Exit Sign - Incandescent Exit Sign Base Case Fixture
- VENDING MACHINES - Existing and new vending machines with illuminated fronts - Vending Machine Controller-Large Machine w/Illuminated Front
- LIGHTING - Large (>20,000 ft2) Office, HtPmp Heat - 2-F32T8 32watt T8 lamp(s) w/ IS Elect. ballast
- LIGHTING - Small (<=20,000 ft2) Retail, HtPmp Heat - 2-F32T8 32watt T8 lamp(s) w/ IS Elect. ballast
- MOTORS - Replace rather than Rewind Open Drip-Proof (ODP) Industrial Motors, 10 HP and smaller - Replace instead of Rewind 7.5 HP 1800 RPM ODP with new, Premium Efficiency motor of same size and type

Table 42: Low Case Results: Best RIM-BPA/TBL BC Ratio Measure for Each Sector and End Use

Sector	End Use	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Residential	HEATING	0.00142	0.00381	1.6516604	2.03743	2.197138	0.561501
Commercial	ENVELOPE	0.00135	0.019691	110.06131	159.7317	142.9525	0.651537
Residential	APPLIANCES	0.00111	0.001712	1.0959389	1.189491	1.245551	0.667924
Commercial	EXIT SIGNS	0.00105	0.002373	1.4681869	1.68	1.702181	0.666012
Other	TRAFFIC SIGNALS	0.00079	0.001895	1.4224507	1.615965	1.705642	0.623158
Commercial	HEATING	0.00072	0.001575	3.6863316	4.717233	8.178473	0.58211
Residential	LIGHTING	0.00065	0.001789	1.0366544	1.053436	1.088397	0.63562
Industrial	MOTORS	0.00056	0.000891	2.6538877	5.633757	4.13539	0.548264
Commercial	APPLIANCES	0.00044	0.000502	1.1612056	1.474298	2.815976	0.651537
Residential	AC	0.00042	0.000874	1.534259	2.094447	3.118524	0.993971
Retail	LIGHTING	0.00038	0.000633	1.0600986	1.119003	1.289272	0.635872
Residential	WATER HEATING	0.00025	0.000288	1.2550009	1.713382	2.905316	0.592306
Residential	ENVELOPE	0.00024	0.000271	1.6130093	3.047789	2.695395	0.573109
Other	VENDING MACHINES	4.3E-05	6.2E-05	0.9175291	1.034029	1.558949	0.806447
Commercial	LIGHTING	0	0	0.7648173	0.768569	1.019761	0.553018

- HEATING - Post79/Pre93 Single Family Construction Convert FAF w/o CAC to HP w/PTCS - Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS

- MOTORS - New Premium Efficiency Open Drip-Proof (ODP) Industrial Motors, 100 - 250 HP - Premium Efficiency 15 HP 1800 RPM ODP
- HEATING - Commercial Small Heat Pump - Heat pump rated HSPF 8.0 and SEER 13 or higher
- LIGHTING - Grocery, HtPmp Heat - 2-F32T8 32watt T8 lamp(s) w/ IS Elect. ballast
- LIGHTING - Restaurant, Gas Heat - 2-F32T8 32watt T8 lamp(s) w/ IS Elect. ballast
- LIGHTING - Residential Lighting - Energy Star CFL Exterior - 26 Watt
- APPLIANCES - Single Family Residence w/Electric Water Heat - Energy Star Dishwasher - Electric DHW
- ENVELOPE - New Low Rise (Less than 5 Stories) Multifamily Dwellings w/Electric Heat - Long Term Super Good Cents Program & Specifications
- TRAFFIC SIGNALS - Existing and new traffic signals - LED Traffic Signals - Replace 12 inch Red Incandescent Left Turn Bay with 12 inch Red LED module
- VENDING MACHINES - Existing and new vending machines with illuminated fronts - Vending Machine Controller-Large Machine w/Illuminated Front
- WATER HEATING - Residence w/Electric Water Heat - EF- 0.91 Domestic Water Heater w/80 gallon rated capacity and minimum 10 year warranty
- EXIT SIGNS - Building or structure where exit signs are required - Energy Star Light Emitting Diode (LED) Exit Sign - Incandescent Exit Sign Base Case Fixture
- ENVELOPE - Small Office Weatherization Floor Insulation - R0 > R19 batt
- APPLIANCES - Multifamily common area or commercial Laundromat w/Electric Dryer and Electric Water Heat - Energy Star Clothes Washer - Commercial Laundry - Electric Water Heater & Dryer
- AC - Residential Dwellings - Energy Star Window Air Conditioner - 19000 Btu/hr

Table 43: Detailed DSM Calculation of Best Base Case Measure: Base Case

		DSM Measure
1	Name	HEATING - Post79/Pre93 Single Family Construction Convert FAF w/oCAC to HP w/PTCS - Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS
2	Sector: Res(1) / Com(2) / Retail(3) / Ind(4) / Other(5)	1
3	End Use: Heating(1) Envelope(2) Lighting(3) Water Heating(4) AC (5) Appliances (6) Exit Signs (7) Motors (8) Traffic Signals (9) Vending Machines (10)	1
4	Original Device (Name)	Forced Air Furnace without Cental AC
5	Replacement Device	Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS
6	Cost of Original Device	$3,868.94
7	Cost of Replacement Device	$4,381.97
8	Measure Life (Years)	18
9	Incentive Basis (Enter 1 for Early Replacement, 2 for Failure Replacement, 3 for Either)	3
10	Incentive as % of Incremental Cost	100%
11	BPA % of incentive	50%
12	BPA Admin Cost $/measure one time cost	$0.00
13	Distribution Utility Admin Cost $/measure one time cost	$0.00
	Annual Demand and Energy Impacts	
14	System Coincident Peak Reduction (KW)	2.7596
15	Local Distribution System Peak Load Reduction (kW)	7.3915
16	Annual Savings @ Site (kwh/yr)	9,468
17	Annual Savings @ Busbar (kwh/yr)	10,190
18	T&D Line Loss Factor	7.625%
19	kW Savings Basis (Enter 1 for System Coincident, 2 for Local Distribution)	1
20	Demand Reduction for Billing Determinants (Enter 1 for System Coincident, 2 for Local Distribution)	2
21	# of Months of Demand Reduction	4
22	Load Distribution Factor	32%
	Lifecycle Avoided Costs per kW or kWh	
23	Peak Period kW Savings (for Gen capacity savings)	2.7596
24	Peak Period kW Savings (for T capacity savings)	0.88
25	Peak Period kW Savings (for Distribution Capacity Savings)	7.39
26	Annual kWh/measure	10190
27	Monthly Peak Demand Reduction (kW) (for billing determinants)	7.39
28	Generation Capacity $/kW	$0.00
29	Transmission $/kW (total 3-yr marginal cost discounted at utility discount rate)	$5.70
30	Avoided Loss Savings $/kW (total 3-year avoided losses)	$7.34
31	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$0.00
32	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at societal discount rate)	$0.00
33	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.46
34	Energy (discounted at societal disc. rate) + Environmental Adder $/kWh (energy per unit cost [33] + {$MWh env. adder cost accruing over 10 yrs discounted at societal disc. rate} / 1000)	$0.65
	BPA Rates and Lost Revenue	
35	Transmission Average Rate $/kW-month	$2.5600
36	Transmission Revenue Loss $/year (trans avg rate [35] * monthly peak demand reduction [27] * months of demand reduction [21])	$75.69
	Distribtuion Utility Rates and Lost Revenue	
37	Total Average Rate $/kWh	$0.0650
38	Total Electricity Revenue Loss $/year (total avg rate [37] * annual kWh/measure [26])	$662.37
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
39	Generation Avoided Cost (gen. capacity per unit cost [28] * peak period kW savings [23])	$0.00
40	Transmission Avoided Cost (trans. per unit cost [29] * Peak Period kW savings [24])	$5.04
41	Avoided Loss Savings $/kW [30] * Peak Period kW Savings [24])	$6.48
42	Local Distribution Company (local distr. per unit cost [31] * peak period kW savings [25])	$0.00
43	Societal Local Distribution Company (local distr. per unit cost [32] * peak period kW savings [25])	$0.00
44	Energy (energy per unit cost [33] * annual kWh/measure [26])	$4,642.08
45	Energy w/ Environment (energy & env. adder per unit cost [34] * annual kWh/measure [26])	$6,644.72
46	Total Electricity Revenue Loss (discounted at utility discount rate)	$7,537.72
47	Total Distribution Utility Rates Avoided (discounted at generator discount rate)	$5,245.82
48	Transmission Revenue Loss	$861.34
49	Lifecycle BPA Incentive Payment	$256.52
50	Lifecycle BPA Admin Cost	$0.00
51	Lifecycle Distribution Utility Incentive Payment	$256.52
52	Lifecycle Distribution Utility Admin Cost	$0.00

Table 44: Detailed DSM Results of Best DSM Measure: Base Case

		HEATING - Post79/Pre93 Single Family Construction Convert FAF w/oCAC to HP w/PTCS - Heat Pump rated HSPF 8.0 or higher and SEER 12 or higher w PTCS
	RIM Test - BPA TBL	
53	Program Cost (BPA Incentive+Trans. Rev. Loss+ BPA Admin)	$1,117.85
54	Program Benefit (Trans Savings)	$5.04
55	Net Savings	($1,112.82)
56	BC Ratio	0.00
	Utility Cost Test - BPA TBl	
57	Program Cost (Incentive + Admin)	$256.52
58	Program Benefit (Trans Savings)	$5.04
59	Net Savings	($251.48)
60	BC Ratio	0.02
	TRC Cost Test	
61	Program Cost (Measure Cost + Admin Costs + Avoided Loss Savings)	$4,388.45
62	Program Benefit (Gen Savings + T Savings + D Savings)	$8,516.05
63	Net Savings	$4,127.60
64	BC Ratio	1.94
	Societal Cost Test	
65	Program Cost (Measure Cost + Admin Costs + Avoided Loss Savings)	$4,388.45
66	Program Benefit (Electric Gen Savings + Trans Savings + Environment)	$10,518.69
67	Net Savings	$6,130.24
68	BC Ratio	2.40
	Participant Cost Test	
69	Program Cost (Buy Device)	$4,381.97
70	Program Benefit (Incentive + Electricity Bill Reduction+ Replace Conv. Device)	$9,627.78
71	Net Savings	$5,245.82
72	BC Ratio	2.20
	RIM Test - Distribution Utility	
73	Program Cost (Dist. Utility Incentive + Dist. Revenue Loss + Utility Admin)	$7,794.23
74	Program Benefit (Trans. Bill Reduction + D Savings + Gen Savings)	$5,503.41
75	Net Savings	($2,290.82)
76	BC Ratio	0.71

Section 11 Appendix 2: DG Results

Table 45: Base Case Results: BC Ratio for Each DG Technology

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Gas Spark Ignition	0.01	1.00	0.56	0.50	0.56	1.03
Cummins Genset	0.01	1.00	0.54	0.48	0.54	1.03
Low Temp (PEM) Fuel Cell	0.01	1.00	0.44	0.49	0.44	0.88
High Temp Fuel Cell	0.01	1.00	0.42	0.48	0.42	0.88
Generic Diesel Engine	0.01	1.00	0.41	0.36	0.41	1.03

Table 46: High Case Results: BC Ratio for Each DG Technology

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Gas Spark Ignition	0.02	1.00	0.73	0.66	0.56	1.28
Cummins Genset	0.02	1.00	0.70	0.63	0.54	1.28
Low Temp (PEM) Fuel Cell	0.02	1.00	0.58	0.62	0.45	1.12
High Temp Fuel Cell	0.02	1.00	0.54	0.60	0.42	1.12
Generic Diesel Engine	0.02	1.00	0.54	0.47	0.42	1.28

Table 47: Low Case Results: BC Ratio for Each DG Technology

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Gas Spark Ignition	0.00	1.00	0.41	0.37	0.56	0.82
Cummins Genset	0.00	1.00	0.39	0.35	0.54	0.82
Low Temp (PEM) Fuel Cell	0.00	1.00	0.32	0.37	0.44	0.66
High Temp Fuel Cell	0.00	1.00	0.30	0.36	0.42	0.66
Generic Diesel Engine	0.00	1.00	0.30	0.26	0.41	0.82

Table 48: Detailed Calculation of DG Results: Base Case

	Calculation	DG Customer Bypass (includes lost retail revenue)
1	DG Device	Gas Spark Ignition
2	BPA Incentive Cost $/kW	$1.83
3	Distribution Utility Incentive Cost $/kW	$0.00
4	Generator Life (Years)	10
5	Fuel Cost $/MMBtu	$3.81
6	Heat Rate Btu/kWh	9,000
7	Capital Cost $/kW	$550.00
8	Install Cost $/kW	$0.00
9	Fixed O&M $/kW-yr	$16.61
10	Variable O&M $/kWh	$0.015
11	Lifecycle BPA Admin Cost	$0.00
12	Lifecycle Distribution Utility Admin Cost	$0.00
	Generator Operating Assumptions	
13	Peak Period kW Savings (at T Constraint)	0.32
14	Annual Load Factor	30%
15	Monthly Peak Demand Reduction (kW) (for billing determinants)	1.00
16	Environmental Externality Benefit? 0=no, 1=yes	0.00
17	Market Energy Price ($/kWh)	$0.040
	Generator Cost Calculations	
18	Fuel Cost $/kWh ($/MMBtu [5] * Heat Rate [6] / 10^6)	$0.03
19	Annual Fuel and O&M Costs $/kW ({fuel cost [18] + var. O&M [10]} * annual load factor [14] * 8760 hrs in a yr + fixed O&M [9])	$146.14
	Lifecycle Generator Costs	
20	Lifecycle Capital Cost ($/kW) (cap. cost [7] + install cost [8])	$550.00
21	Lifecycle Fuel and O&M Cost ($/kW) (Discounted at Generator WACC)	$910.26
22	Total Lifecycle Cost ($/kW)	$1,460.26
23	Lifecycle Fuel and O&M Cost ($/kW) (Discounted at Societal Discount Rate)	$1,284.04
	Per Unit Lifecycle Avoided Costs	
24	Generation Capacity $/kW	$0.00
25	Transmission $/kW (total 10-year trans. marginal cost discounted at utility discount rate)	$5.70
26	Avoided Loss Savings $/kW (total 3-year avoided losses)	$7.34
27	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$0.00
28	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at societal discount rate)	$0.00
29	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.31
30	Energy (discounted at Societal Discount Rate) + Environmental Adder (If Clean Generation) $/kWh (energy per unit cost discounted at Societal Discount Rate + {$MWh env. adder cost accruing over 10 yrs discounted at Societal Discount Rate} / 1000)	$0.35
31	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at generator disc. rate/1000)	$0.25
	Rates and Lost Revenue	
32	Total Average Rate $/kWh	$0.0500
33	Transmission Average Rate $/kW-month	$2.5600
34	Total Electricity Revenue Loss $/year (total avg rate [32] * annual load factor [14] * 8760 hrs in a yr)	$131.40
35	Transmission Revenue Loss $/year (trans. avg. rate [33] * monthly peak demand reduction [15] * annual load factor [14] * 12 months)	$30.72
	Lifecycle Avoided Costs per kW, Revenue per kW, Incentive per kW	
36	Generation Avoided Cost (gen. capacity per unit cost [24] * peak period kW savings [13])	$0.00
37	Transmission Avoided Cost (trans. per unit cost [25] * peak period kW savings [13])	$1.83
38	Avoided Loss Savings $/kW [26] * Peak Period kW Savings[13])	$2.35
39	Local Distribution Company (local distr. per unit cost [27] * peak period kW savings [13])	$0.00
40	Local Distribution Company (local distr. per unit cost [28] * peak period kW savings [13])	$0.00
41	Energy (energy per unit cost [29] * annual load factor [14] * 8760 hrs in a yr)	$816.70
42	Energy w/ Environment (energy & env. adder per unit cost [30] * annual load factor [14] * 8760 hrs in a yr)	$924.29
43	Total Electricity Revenue Loss (total annual loss [34] accruing over 10 years, discounted at utility discount rate)	$1,020.11
44	Total Distribution Utility Rates Avoided (total distribution utility annual loss [34] accruing over 10 years, discounted at financing rate of generator)	$818.42
45	Sales of Energy (energy per unit cost [31] * annual load factor [14] * 8760 hours in a yr)	$0.00
46	Transmission Revenue Loss (total annual loss [35] accruing over 10 years, discounted at utility discount rate)	$238.49
47	Lifecycle BPA Incentive Payment	$1.83
48	Lifecycle Distribution Utility Incentive Payment	$0.00
49	Lifecycle BPA Admin Cost	$0.00
50	Lifecycle Distribution Utility Admin Cost	$0.00

Table 49: Detailed Results of Best DG Measure: Base Case

		DG Customer Bypass (includes lost retail revenue)
	RIM Test - BPA TBL	
51	Program Cost (Incentive[47] + T Rev. Loss[46] + Admin[49])	$240.32
52	Program Benefit (T Savings[37])	$1.83
53	Net Savings	($238.49)
54	BC Ratio	0.01
	Utility Cost Test - BPA TBL	
55	Program Cost (Incentive[47] + Admin[49])	$1.83
56	Program Benefit (T Savings[37])	$1.83
57	Net Savings	$0.00
58	BC Ratio	1.00
	TRC Cost Test	
59	Program Cost (DG Cost[22] + Admin Costs[49,50]+Avoided Loss Savings[38])	$1,462.61
60	Program Benefit (Gen Cap Savings[36] + Energy [41] + T Savings[37] + D Savings[39])	$818.52
61	Net Savings	($644.08)
62	BC Ratio	0.56
	Societal Cost Test	
63	Program Cost (DG Cost[20,23] + Admin Costs[49,50] +Avoided Loss Savings[38])	$1,836.39
64	Program Benefit (Gen Cap Savings [36 Energy w/ Environment [42] + T Savings[37] + D Savings[40])	$926.11
65	Net Savings	($910.27)
66	BC Ratio	0.50
	Participant Cost Test	
67	Program Cost (DG Costs[22])	$1,460.26
68	Program Benefit (Incentive[47,48] + Electricity Bill Reduction or Energy sales[44 or 45])	$820.25
69	Net Savings	($640.01)
70	BC Ratio	0.56
	RIM Test - Distribution Utility	
71	Program Cost (Incentive[48] + Dist. Revenue Loss[43] + Utility Admin[50])	$1,020.11
72	Program Benefit (Trans. Bill Reduction[46] + D Savings[27] + Gen Savings[41] in bypass scenario)	$1,055.19
73	Net Savings	$35.08
74	BC Ratio	1.03

Section 11. Appendix 3: G Results

Table 50: Base Case Results: BC Ratio for Each Large Scale Generation Technology

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Combined Cycle Combustion Turbine	1.00	1.00	1.56	1.10	0.99	Not Effected
Simple Cycle Combustion Turbine	1.00	1.00	0.71	0.63	0.57	Not Effected

Table 51: High Case Results: BC Ratio for Each Large Scale Generation Technology

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Combined Cycle Combustion Turbine	1.00	1.00	2.03	1.44	1.30	Not Effected
Simple Cycle Combustion Turbine	1.00	1.00	0.93	0.82	0.75	Not Effected

Table 52: Low Case Results: BC Ratio for Each Large Scale Generation Technology

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
Combined Cycle Combustion Turbine	1.00	1.00	1.13	0.80	0.72	Not Effected
Simple Cycle Combustion Turbine	1.00	1.00	0.52	0.46	0.41	Not Effected

Table 53: Detailed Calculation of G Results: Base Case

	Calculation	DG Merchant Plant (Connected to BPA)
1	DG Device	Combined Cycle Combustion Turbine
2	BPA Incentive Cost $/kW	$1.83
3	Distribution Utility Incentive Cost $/kW	$0.00
4	Generator Life (Years)	25
5	Fuel Cost $/MMBtu	$3.81
6	Heat Rate Btu/kWh	7,618
7	Capital Cost $/kW	$523.06
8	Install Cost $/kW	$0.00
9	Fixed O&M $/kW-yr	$23.23
10	Variable O&M $/kWh	$0.001
11	Lifecycle BPA Admin Cost	$0.00
12	Lifecycle Distribution Utility Admin Cost	$0.00
	Generator Operating Assumptions	
13	Peak Period kW Savings (at T Constraint)	0.32
14	Annual Load Factor	90%
15	Monthly Peak Demand Reduction (kW) (for billing determinants)	0.00
16	Environmental Externality Benefit? 0=no, 1=yes	0.00
17	Market Energy Price ($/kWh)	$0.040
	Generator Cost Calculations	
18	Fuel Cost $/kWh ($/MMBtu [5] * Heat Rate [6] / 10^6)	$0.03
19	Annual Fuel and O&M Costs $/kW ({fuel cost [18] + var. O&M [10]} * annual load factor [14] * 8760 hrs in a yr + fixed O&M [9])	$256.79
	Lifecycle Generator Costs	
20	Lifecycle Capital Cost ($/kW) (cap. cost [7] + install cost [8])	$523.06
21	Lifecycle Fuel and O&M Cost ($/kW) (Discounted at Generator WACC)	$2,189.46
22	Total Lifecycle Cost ($/kW)	$2,712.52
23	Lifecycle Fuel and O&M Cost ($/kW) (Discounted at Societal Discount Rate)	$4,605.61
	Per Unit Lifecycle Avoided Costs	
24	Generation Capacity $/kW	$0.00
25	Transmission $/kW (total 10-year trans. marginal cost discounted at utility discount rate)	$5.70
26	Avoided Loss Savings $/kW (total 3-year avoided losses)	$7.34
27	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at utility discount rate)	$0.00
28	Local Distribution Company $/kW (local distr. marginal cost accruing over 10 years, discounted at societal discount rate)	$0.00
29	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at utility disc. rate / 1000)	$0.54
30	Energy (discounted at Societal Discount Rate) + Environmental Adder (If Clean Generation) $/kWh (energy per unit cost discounted at Societal Discount Rate + {$MWh env. adder cost accruing over 10 yrs discounted at Societal Discount Rate} / 1000)	$0.72
31	Energy $/kWh ($MWh marg. cost accruing over 10 yrs discounted at generator disc. rate/1000)	$0.34
	Rates and Lost Revenue	
32	Total Average Rate $/kWh	$0.0500
33	Transmission Average Rate $/kW-month	$2.5600
34	Total Electricity Revenue Loss $/year (total avg rate [32] * annual load factor [14] * 8760 hrs in a yr)	$0.00
35	Transmission Revenue Loss $/year (trans. avg. rate [33] * monthly peak demand reduction [15] * annual load factor [14] * 12 months)	$0.00
	Lifecycle Avoided Costs per kW, Revenue per kW, Incentive per kW	
36	Generation Avoided Cost (gen. capacity per unit cost [24] * peak period kW savings [13])	$0.00
37	Transmission Avoided Cost (trans. per unit cost [25] * peak period kW savings [13])	$1.83
38	Avoided Loss Savings $/kW [26] * Peak Period kW Savings[13])	$2.35
39	Local Distribution Company (local distr. per unit cost [27] * peak period kW savings [13])	$0.00
40	Local Distribution Company (local distr. per unit cost [28] * peak period kW savings [13])	$0.00
41	Energy (energy per unit cost [29] * annual load factor [14] * 8760 hrs in a yr)	$4,229.31
42	Energy w/ Environment (energy & env. adder per unit cost [30] * annual load factor [14] * 8760 hrs in a yr)	$5,660.39
43	Total Electricity Revenue Loss (total annual loss [34] accruing over 10 years, discounted at utility discount rate)	$0.00
44	Total Distribution Utility Rates Avoided (total distribution utility annual loss [34] accruing over 10 years, discounted at financing rate of generator)	$0.00
45	Sales of Energy (energy per unit cost [31] * annual load factor [14] * 8760 hours in a yr)	$2,690.90
46	Transmission Revenue Loss (total annual loss [35] accruing over 10 years, discounted at utility discount rate)	$0.00
47	Lifecycle BPA Incentive Payment	$1.83
48	Lifecycle Distribution Utility Incentive Payment	$0.00
49	Lifecycle BPA Admin Cost	$0.00
50	Lifecycle Distribution Utility Admin Cost	$0.00

Table 54: Detailed Results of Best G Measure: Base Case

		DG Merchant Plant (Connected to BPA)
	RIM Test - BPA TBL	
51	Program Cost (Incentive[47] + T Rev. Loss[46] + Admin[49])	$1.83
52	Program Benefit (T Savings[37])	$1.83
53	Net Savings	$0.00
54	BC Ratio	1.00
	Utility Cost Test - BPA TBL	
55	Program Cost (Incentive[47] + Admin[49])	$1.83
56	Program Benefit (T Savings[37])	$1.83
57	Net Savings	$0.00
58	BC Ratio	1.00
	TRC Cost Test	
59	Program Cost (DG Cost[22] + Admin Costs[49,50]+Avoided Loss Savings[38])	$2,714.87
60	Program Benefit (Gen Cap Savings[36] + Energy [41] + T Savings[37] + D Savings[39])	$4,231.13
61	Net Savings	$1,516.26
62	BC Ratio	1.56
	Societal Cost Test	
63	Program Cost (DG Cost[20,23] + Admin Costs[49,50] +Avoided Loss Savings[38])	$5,131.02
64	Program Benefit (Gen Cap Savings [36 Energy w/ Environment [42] + T Savings[37] + D Savings[40])	$5,662.22
65	Net Savings	$531.20
66	BC Ratio	1.10
	Participant Cost Test	
67	Program Cost (DG Costs[22])	$2,712.52
68	Program Benefit (Incentive[47,48] + Electricity Bill Reduction or Energy sales[44 or 45])	$2,692.72
69	Net Savings	($19.80)
70	BC Ratio	0.99

Section 12. Appendix 4: DR Results

Table 55: Base Case Results: BC Ratio for Each DR Measure

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
BPA (Conceptual)	1.00	1.00	0.33	0.35	0.42	0.80
Day-Ahead Demand Response Program	0.21	0.21	0.33	0.36	0.87	0.80
Energy Exchange Program	0.12	0.12	0.33	0.35	1.04	0.80
Demand Exchange	0.12	0.12	0.33	0.36	1.25	0.80
Voluntary Load Reduction	0.04	0.04	0.31	0.33	1.39	0.80
Demand Buy Back	0.04	0.04	0.30	0.33	1.39	0.80
Emergency Demand Response Program	0.03	0.03	0.33	0.36	3.67	0.80
Emergency Response Program	0.03	0.03	0.33	0.36	3.67	0.80
Scheduled Load Reduction Program	0.03	0.03	0.29	0.32	1.04	0.80
Reliability Program Rider	0.03	0.03	0.31	0.35	3.13	0.80
Demand Bidding Program	0.02	0.02	0.31	0.33	2.80	0.80
Capacity Program - Interruptible Tariff	0.01	0.01	0.29	0.31	1.31	0.80
Economy Program - Interruptible Tariff	0.01	0.01	0.29	0.31	1.31	0.80
Energy Cooperative (Curtailment Service Cooperative)	0.01	0.01	0.31	0.32	2.50	0.80
Com/Ind. Base Interruptible Program	0.01	0.01	0.30	0.32	5.26	0.80
Interruptible Service	0.00	0.00	0.29	0.31	3.15	0.80
Demand Relief Program	0.00	0.00	0.31	0.33	9.72	0.80
The Alliance Option C - Curtailable	0.00	0.00	0.00	0.00	2.86	0.80
The Alliance Option B - Curtailable	0.00	0.00	0.00	0.00	3.29	0.80
The Alliance Option A - Interruptible	0.00	0.00	0.00	0.00	3.19	0.80

Table 56: High Case Results: BC Ratio for Each DR Measure

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
BPA (Conceptual)	1.00	1.00	0.70	0.73	1.14	1.05
Day-Ahead Demand Response Program	0.69	0.69	0.69	0.73	1.64	1.05
Energy Exchange Program	0.41	0.41	0.70	0.73	1.95	1.05
Demand Exchange	0.41	0.41	0.69	0.73	2.34	1.05
Voluntary Load Reduction	0.13	0.13	0.70	0.73	2.61	1.05
Demand Buy Back	0.12	0.12	0.70	0.73	2.61	1.05
Emergency Demand Response Program	0.11	0.11	0.69	0.73	6.87	1.05
Emergency Response Program	0.11	0.11	0.69	0.73	6.87	1.05
Scheduled Load Reduction Program	0.10	0.10	0.70	0.73	1.95	1.05
Reliability Program Rider	0.09	0.09	0.68	0.73	5.87	1.05
Demand Bidding Program	0.06	0.06	0.70	0.73	5.25	1.05
Capacity Program - Interruptible Tariff	0.05	0.05	0.69	0.73	2.45	1.05
Economy Program - Interruptible Tariff	0.05	0.05	0.69	0.73	2.45	1.05
Energy Cooperative (Curtailment Service Cooperative)	0.04	0.04	0.73	0.73	4.68	1.05
Com/Ind. Base Interruptible Program	0.02	0.02	0.70	0.73	9.87	1.05
Interruptible Service	0.02	0.02	0.69	0.73	5.91	1.05
Demand Relief Program	0.02	0.02	0.70	0.73	18.23	1.05
The Alliance Option C - Curtailable	0.00	0.00	0.00	0.00	5.35	1.05
The Alliance Option B - Curtailable	0.00	0.00	0.00	0.00	6.18	1.05
The Alliance Option A - Interruptible	0.00	0.00	0.00	0.00	5.98	1.05

Table 57: Low Case Results: BC Ratio for Each DR Measure

	RIM-BPA/TBL	Utility Cost	TRC Cost	Societal Cost	Participant Cost	RIM-LDC
BPA (Conceptual)	1.00	1.00	0.23	0.25	0.37	0.58
Day-Ahead Demand Response Program	0.09	0.09	0.23	0.26	0.87	0.58
Energy Exchange Program	0.05	0.05	0.23	0.26	1.04	0.58
Demand Exchange	0.05	0.05	0.23	0.26	1.25	0.58
Voluntary Load Reduction	0.02	0.02	0.22	0.24	1.39	0.58
Demand Buy Back	0.01	0.01	0.22	0.24	1.39	0.58
Emergency Demand Response Program	0.01	0.01	0.23	0.26	3.67	0.58
Emergency Response Program	0.01	0.01	0.23	0.26	3.67	0.58
Scheduled Load Reduction Program	0.01	0.01	0.21	0.24	1.04	0.58
Reliability Program Rider	0.01	0.01	0.22	0.25	3.13	0.58
Demand Bidding Program	0.01	0.01	0.22	0.24	2.80	0.58
Capacity Program - Interruptible Tariff	0.01	0.01	0.21	0.24	1.31	0.58
Economy Program - Interruptible Tariff	0.01	0.01	0.21	0.24	1.31	0.58
Energy Cooperative (Curtailment Service Cooperative)	0.00	0.00	0.22	0.24	2.50	0.58
Com/Ind. Base Interruptible Program	0.00	0.00	0.22	0.24	5.26	0.58
Interruptible Service	0.00	0.00	0.21	0.24	3.15	0.58
Demand Relief Program	0.00	0.00	0.22	0.24	9.72	0.58
The Alliance Option C - Curtailable	0.00	0.00	0.00	0.00	2.86	0.58
The Alliance Option B - Curtailable	0.00	0.00	0.00	0.00	3.29	0.58
The Alliance Option A - Interruptible	0.00	0.00	0.00	0.00	3.19	0.58

Table 58: Detailed Calculation of DR Results: Base Case

		DR-DLC Measure
1	DR-DLC Program Company	Conceptual DR Program
2	DR-DLC Program Name	BPA (Conceptual)
3	Customer Cost of Dropped Load ($/kWh) (Lost Productivity)	$0.15
4	BPA Incentive Cost $/kW-year	$0.64
5	Distribution Utility Incentive Cost $/kW-year	$0.00
6	Measure Life (Years)	3
	Annual Demand and Energy Impacts	
7	Peak Period kW Savings (for T&D capacity savings)	0.32
8	Number of hours per year	50
9	Monthly Peak Demand Reduction (kW) (for billing determinants)	0.00
10	Months in Peak Load Season for Curtailment	3
11	BPA Admin Cost $/measure one time cost	$0.00
12	Distribution Utility Admin Cost $/measure one time cost	$0.00
13	Customer Cost of Dropped Load ($/kW lifecycle) ([3] accruing over 3 yrs, discounted at generator rates)	$20.09
14	Customer Cost of Dropped Load ($/kW lifecycle) ([3] accruing over 3 yrs, discounted at societal disc. rates)	$21.85
15	BPA Incentive Cost $/kW lifecycle ([4] accruing over program life, discounted at utility discount rate)	$1.83
16	Distribution Utility Incentive Cost $/kW lifecycle ([5] accruing over program life, discounted at utility discount rate)	$0.00
	Lifecycle Avoided Costs per kW or kWh	
17	Generation Capacity $/kW (discounted at utility discount rate)	$0.00
18	Transmission $/kW (total 3-year marginal cost discounted at utility discount rate)	$5.70
19	Avoided Loss Savings $/kW (total 3-year avoided losses)	$7.34
20	Local Distribution Company $/kW (local distr. marginal cost accruing over 3 years, discounted at utility discount rate)	$0.00
21	Local Distribution Company $/kW (local distr. marginal cost accruing over 3 years, discounted at societal discount rate)	$0.00
22	Energy $/kWh ($MWh wholesale energy cost accruing over 3 yrs discounted at utility disc. rate / 1000)	$0.11
23	Energy $/kWh (discounted at societal disc. rate) + Environmental Adder $/kWh (discounted at societal disc. Rate)	$0.13
	Rates, Administration Costs, and Lost Revenue	
24	Total Average Rate $/kWh	$0.0500
25	Transmission Average Rate $/kW-month	$2.5600
26	Distribution Utility Electricity Revenue Loss $/year (total avg rate [24] * annual kWh/measure [8])	$2.50
27	Transmission Revenue Loss $/year (trans avg rate [25] * monthly peak demand reduction [9] * months in peak load season [10])	$0.00
	Lifecycle Avoided Costs, Revenue, Incentive per measure	
28	Generation Avoided Cost (gen. capacity per unit cost [17] * peak period kW savings [7])	$0.00
29	Transmission Avoided Cost (trans. per unit cost [18] * peak period kW savings [7])	$1.83
30	Avoided Loss Savings $/kW [19] * Peak Period kW Savings[7])	$2.35
31	Distribution Avoided Cost (local distr. per unit cost [20] * peak period kW savings [7])	$0.00
32	Distribution Avoided Cost (local distr. per unit cost [21] * peak period kW savings [7])	$0.00
33	Energy (energy per unit cost [22] * annual kWh/measure [8])	$5.66
34	Energy w/ Environment (energy & env. adder per unit cost [23] * annual kWh/measure [8])	$6.71
35	Total Electricity Revenue Loss [26] (discounted at utility rates)	$7.08
36	Total Distribution Utility Rates Avoided [26] (discounted at generator rates)	$6.70
37	Transmission Revenue Loss [27] (discounted at utility rates)	$0.00
38	Lifecycle BPA Incentive Payment [15]	$1.83
39	Lifecycle Distribution Utility Incentive Payment [16]	$0.00
40	Lifecycle BPA Admin Cost [11]	$0.00
41	Lifecycle Distribution Utility Admin Cost [12]	$0.00

Table 59: Detailed Results of Best DR Measure: Base Case

		DR-DLC Measure
	RIM Test - BPA TBL	
42	Program Cost (Incentive [38] + Trans. Rev. Loss [37] + Admin [40])	$1.83
43	Program Benefit (Trans Savings [29])	$1.83
44	Net Savings	$0.00
45	BC Ratio	1.00
	Utility Cost Test - BPA TBL	
46	Program Cost (Incentive [38] + Admin [40])	$1.83
47	Program Benefit (Trans Savings [29])	$1.83
48	Net Savings	$0.00
49	BC Ratio	1.00
	TRC Cost Test	
50	Program Cost (Cost of Dropped Load [13] + Admin Costs [40,41])+Avoided Loss Savings[30]	$22.44
51	Program Benefit (Gen Savings [28,33] + T Savings [29] + D Savings [31])	$7.49
52	Net Savings	($14.95)
53	BC Ratio	0.33
	Societal Cost Test	
54	Program Cost (Cost of Dropped Load [14] + Admin Costs [40,41])+Avoided Loss Savings[30]	$24.20
55	Program Benefit (Gen Savings [28,34] + T Savings [29] + D Savings [32])	$8.53
56	Net Savings	($15.67)
57	BC Ratio	0.35
	Participant Cost Test	
58	Program Cost (Cost of Dropped Load [13])	$20.09
59	Program Benefit (Incentives [38,39] + Electricity Bill Reduction [36])	$8.52
60	Net Savings	($11.57)
61	BC Ratio	0.42
	RIM Test - Distribution Utility	
62	Program Cost (Dist. Utility Incentive [16] + Dist. Revenue Loss [35] + Utility Admin [12])	$7.08
63	Program Benefit (Trans. Bill Reduction [37] + D Savings [31] + Gen Savings [28,33])	$5.66
64	Net Savings	($1.41)
65	BC Ratio	0.80

Section 13. Appendix 5: Glossary

'Arctic Express' weather event

A 1-in-20 year extreme cold temperatures resulting from the southern flow of northern Arctic air into the United States.

Avoided Loss Savings

Lost savings from an avoided reduction of electricity losses on the transmission system that occur because the transmission system upgrades are deferred.

B/C ratios

Benefit / Cost ratio is a measure of cost-effectiveness calculated as the ratio of benefits of a particular measure to the costs of the measure. The benefits and costs included depend upon the particular cost test, but in all cases a measure is cost-effective under a particular cost test if the B/C ratio is greater than one.

BPA

Bonneville Power Administration.

Canadian Entitlement

Canada's one half share of the additional power produced on the Columbia River in the western United States as a result of the 1961 Columbia River Treaty. Canada sold its share of the power benefits for a 30-year period to a consortium of United States utilities and delivery of the Canadian Entitlement began in 1998.

Columbia River Treaty

A United States/Canadian treaty signed in 1961, which led to the construction of three storage dams on the Columbia River system in Canada and one in the United States. Under the Treaty, Canada and the United States equally share the benefits of the additional power that can be generated at dams downstream in the United States because of the storage at the upstream Treaty reservoirs. Canada's half of the downstream power benefits are called the Canadian Entitlement (Entitlement).

Cost Test

A cost test is the approach used to evaluate the cost-effectiveness of a measure. Each cost test evaluates the cost-effectiveness from a different perspective, i.e. ratepayer, utility, participant, societal.

Demand Reduction Programs

Programs implemented by a utility to influence the level or timing of customers' energy demand in order to optimize the use of available utility resources

Demand Response Program

Programs implemented by a utility to reduce customer loads during system peaks. Demand response programs addressed by this study include Direct Load Control (DLC), interruptible/curtailable rates, and demand bidding (i.e. the Demand Exchange).

Direct Load Control

A method of insuring a proper balance of supply and demand, usually through the use of direct measures designed to decrease demand; the application of direct control over system load. Examples of direct load control include rolling blackouts and brownouts, mandatory service interruptions during peak demand periods, and at the most drastic stage, manual disconnection of customer equipment by the utility.

Demand Side Management (DSM)

Measures taken by a utility to influence the level or timing of customers' energy demand in order to optimize the use of available utility resources.

Direct Service Industries (DSIs)

Industrial customers that take transmission service directly from BPA.

Distribution Factor

See 'Load Flow Distribution Factor'

Distributed Generation (DG)

Generation equipment that is placed in the system to benefit the transmission and distribution delivery system in addition to providing capability of generating energy. Typically, distributed generation is sized smaller than conventional central station generation.

Environmental Adder

The societal cost on the environment of any activity. This cost is not a direct cost to, but is an externality born by society.

Environmental Externality

A non-monetary cost to society of environmental degradation.

FERC

Federal Energy Regulatory Commission.

Firm Transmission Capacity

Firm transmission capacity is the amount of transmission capacity that can be (and in many cases must be) guaranteed to be available at a given time.

Generation Avoided Costs

The cost savings achieved by reducing the need for generation. This savings does not include savings that may result in the transmission and distribution system.

Heat Rate

Measure of the amount of thermal energy needed to generate a given amount of electrical energy.

Interruptible/Curtailable Contracts

Contracts between utilities and customers that allow utilities to reduce customers' loads under predetermined terms and conditions.

ISO

Independent System Operator

KEL

Kangley Echo Lake

Lifecycle Costs/Benefits

The present value of the costs or benefits over the life of the alternative.

Load Duration Curve

A graph showing all levels of demand (or load) on an electric utility's system, sorted by decreasing size, and the amount of time (or % of time) that any given demand level equaled or exceeded that demand.

Load Flow Distribution Factor

The ratio of the MW change at the constraint on the system (ie. Covington substation) to the MW change at the source (ie. downtown Seattle).

Loss Factor

Measures the relationship between peak capacity losses and average annual losses. To calculate the MWh losses associated with peak capacity losses, the following formula is used:

Total MWh losses = Peak Capacity Loss x Loss Factor x 8,760 (number of hours in a year)

LRIC

Long-run incremental cost.

Measure

A method of reducing demand on the system such as an incentive to a customer to install more efficient air conditioning or switch to an alternative fuel.

Merchant Plant

Merchant plants are electric generating plants that sell power competitively on the wholesale market. They produce only wholesale power for which the price and supply of the power is not regulated by state or local authorities. Merchant power plants are not considered utilities because they do not sell any of their power to retail electric customers.

NEPA

National Environmental Policy Act

NWPPC

Northwest Power Planning Council, or 'The Council'

NWPP

Northwest Power Pool

Overload

A condition in any circuit in which actual current flow exceeds either the expected load or the rated load. Both conditions are potentially hazardous to devices attached to the circuit.

PBL

BPA's Power Business Line

Peak Loss Savings

The reduction in capacity losses during system peak times

Penetration Potential

The potential number of customers or the percentage of a particular market segment that can adopt a DSM/DR/DLC measure.

Price Based Dispatch Program

Voluntary participation programs where the price for curtailment or interruption is determined through a price convergence mechanism (i.e. auction, real-time pricing, etc.)

Ratepayer Impact Measure (RIM Test)

A perspective to evaluate program cost-effectiveness. The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program.

Revenue Requirement

Total amount of money that must be collected from customers to pay all operating and capital costs.

RTO

Regional Transmission Operator

Societal Cost Test

A perspective to evaluate program cost-effectiveness. The Societal Cost Test is similar to the Total Resources Cost Test, but includes savings due to environmental externalities.

TBL

BPA's Transmission Business Line

Total Resource Cost Test (TRC test)

A perspective to evaluate program cost-effectiveness. The TRC test evaluates measures from a societal perspective, but does not include externality effects.

Transmission Avoided Cost

The costs avoided by not making transmission upgrades. In this study, transmission avoided costs are calculated as the value of deferring the transmission upgrades:

Deferral Value = Nominal Cost in Year (i) x (1- ((1+Inflation Rate)/(1+Discount Rate))^Δt)

Utility Cost Test

A perspective to evaluate program cost-effectiveness. The utility cost test evaluates measures from the perspective from all ratepayers (both participants and non-participants).

VOS

Value of service

WECC

Western Electricity Coordinating Council